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INT CL^7 **E21B**
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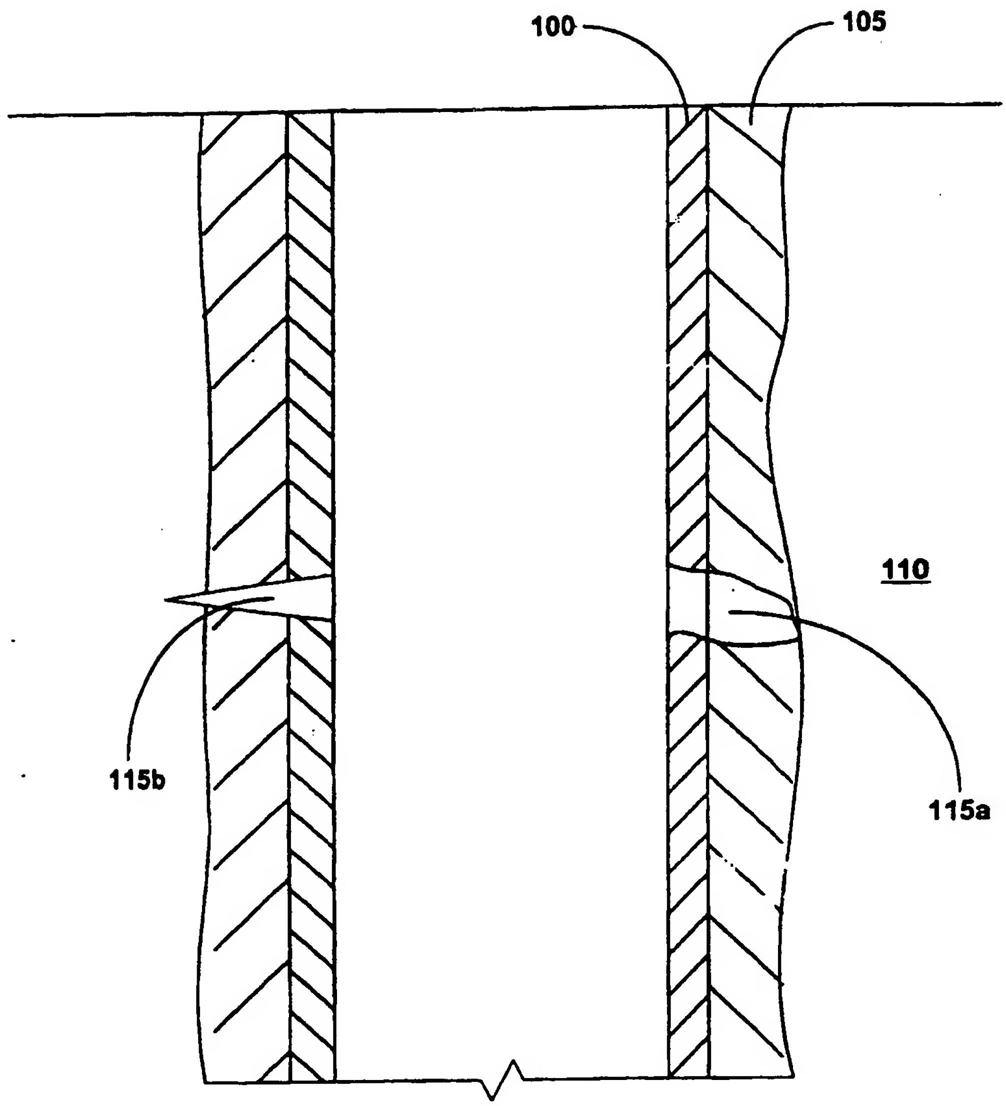

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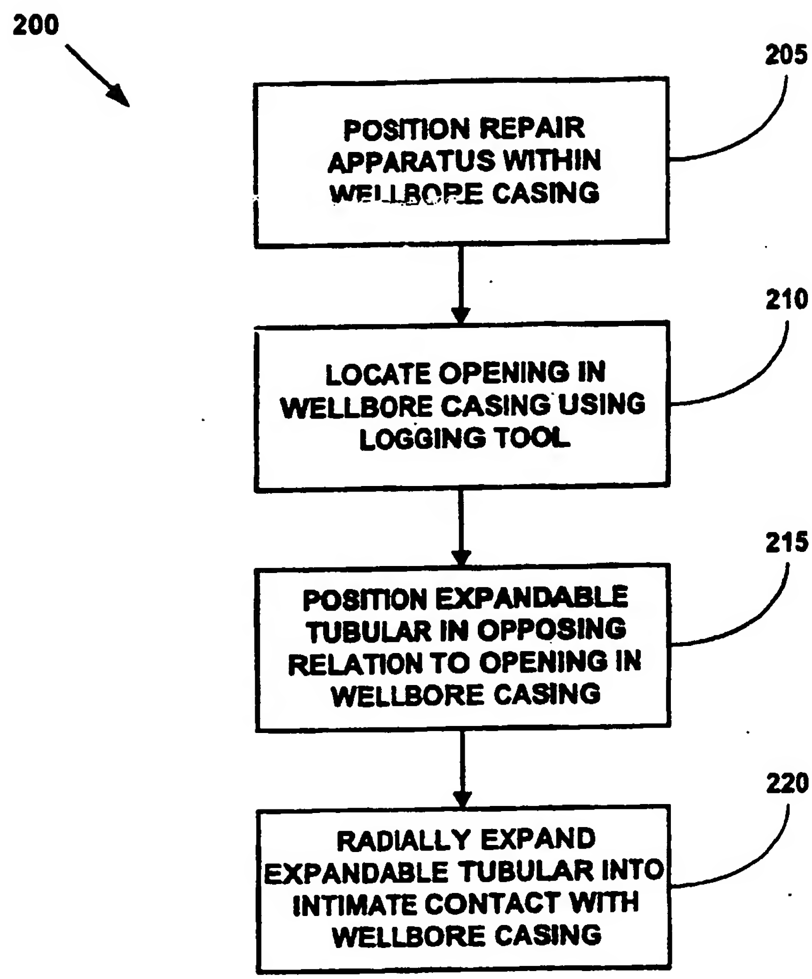
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205
POSITION REPAIR APPARATUS WITHIN WELLBORE CASING
210
LOCATE OPENING IN WELLBORE CASING USING LOGGING TOOL
215
POSITION EXPANDABLE TUBULAR IN OPPOSING RELATION TO OPENING IN WELLBORE CASING
220
RADIALLY EXPAND EXPANDABLE TUBULAR INTO INTIMATE CONTACT WITH WELLBORE CASING

FIGURE 2

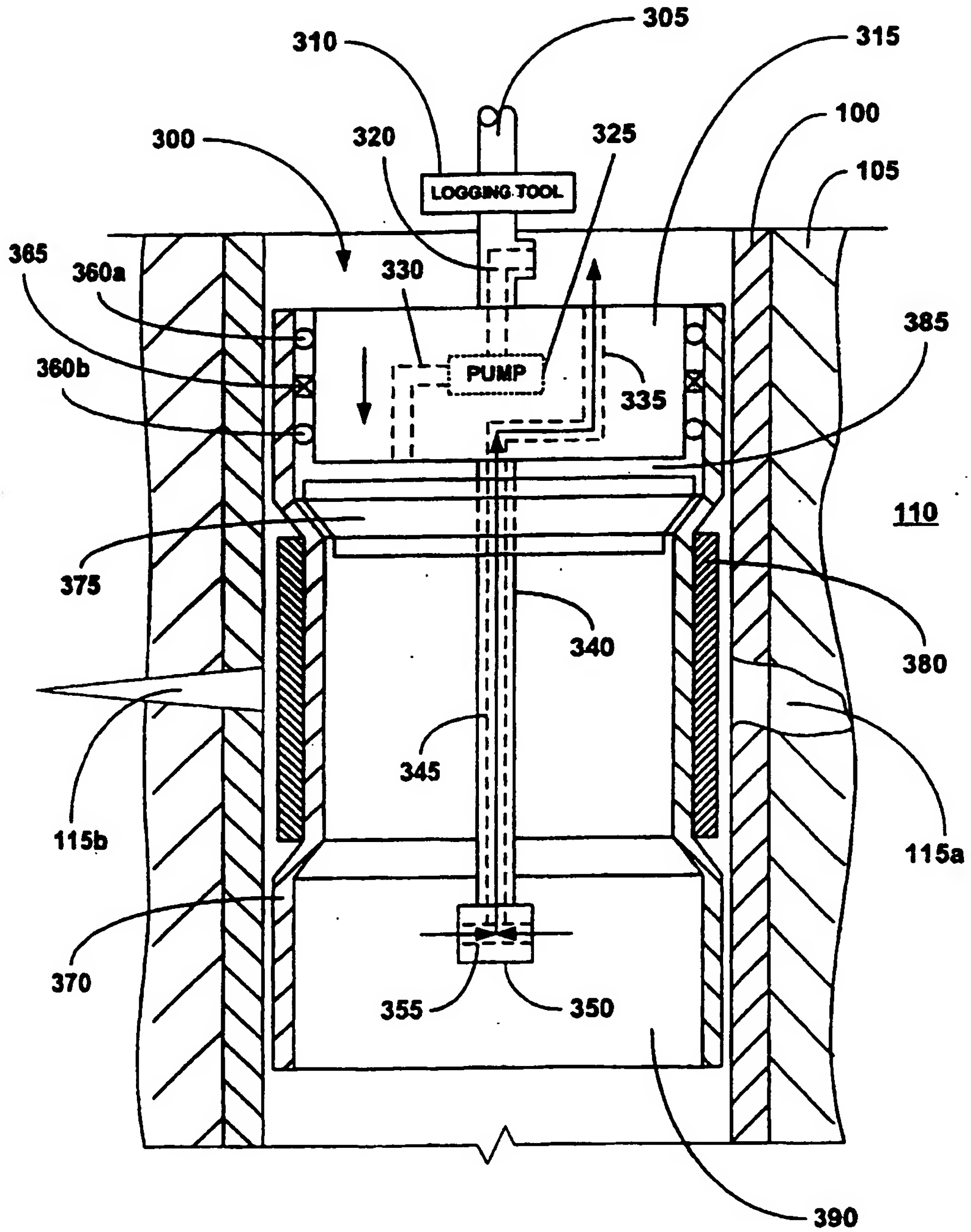
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FIGURE 3a

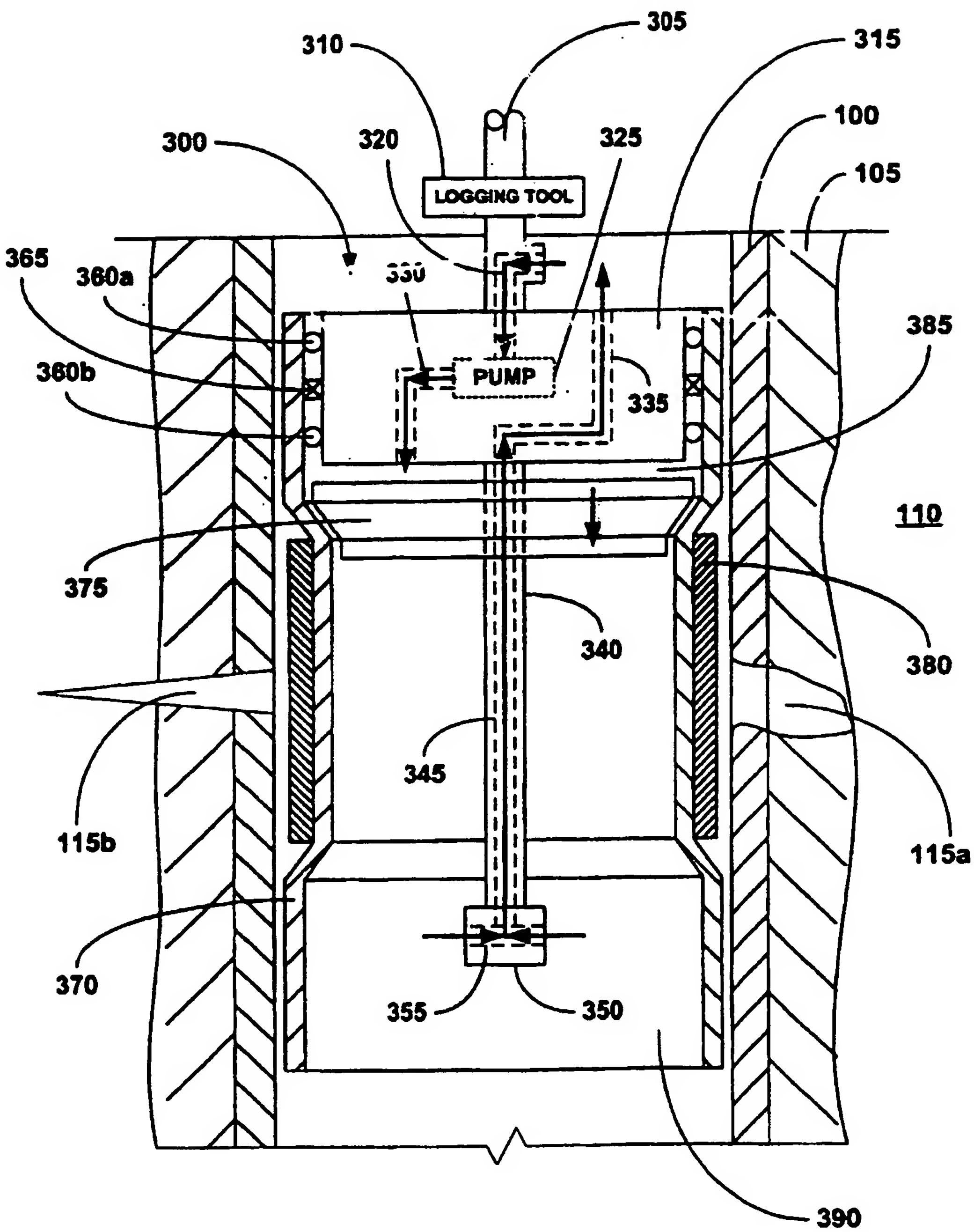
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FIGURE 3b

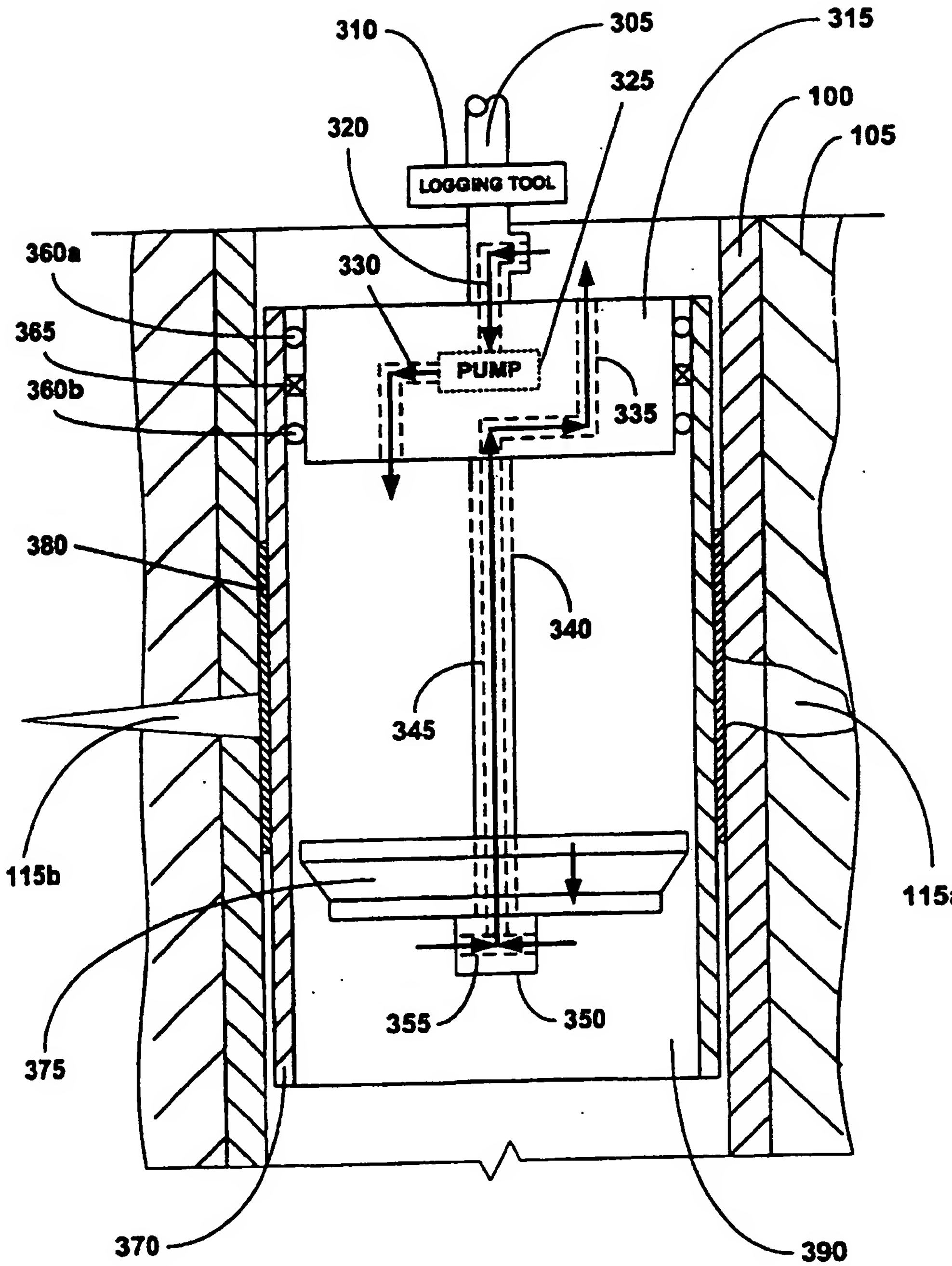
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FIGURE 3c

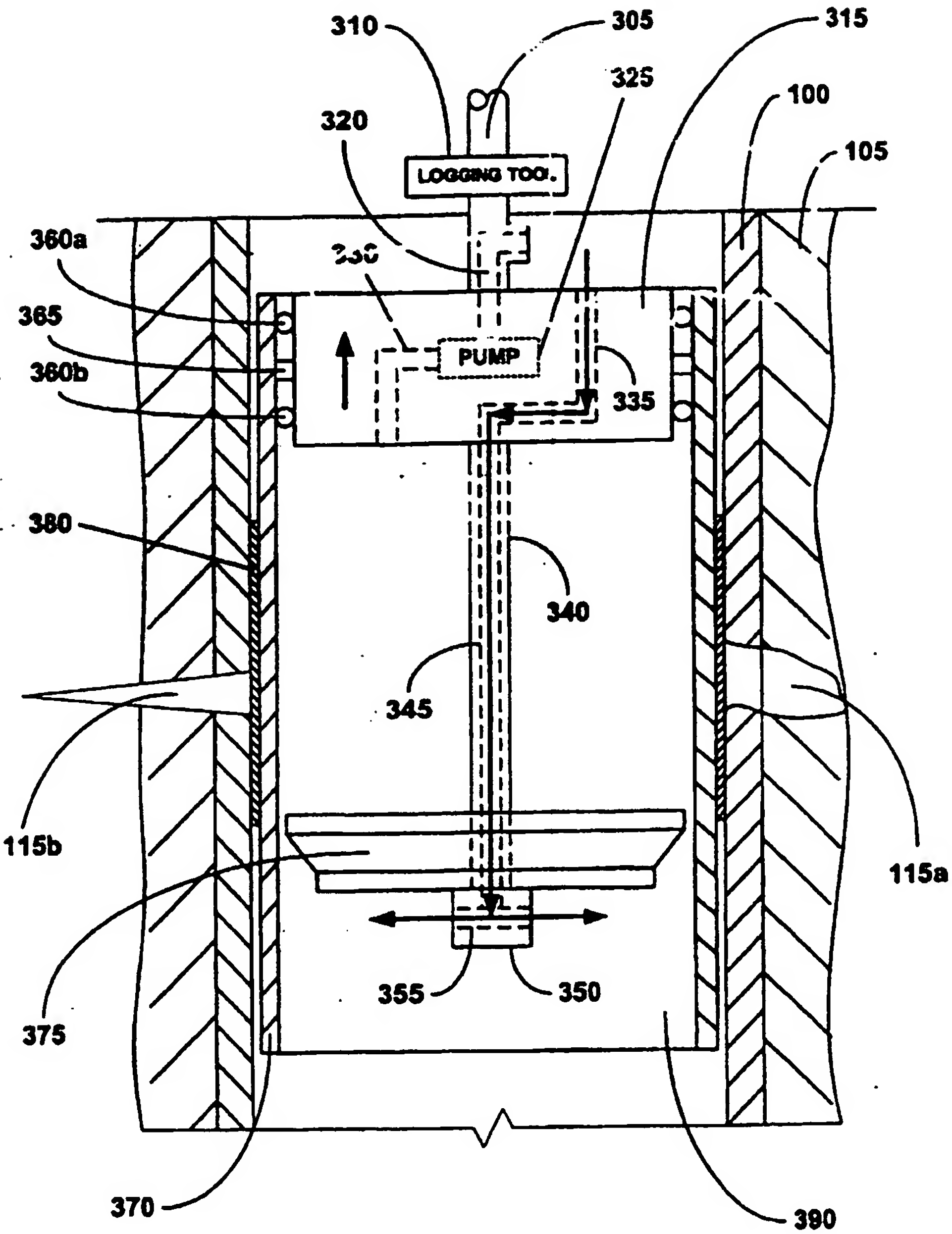

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FIGURE 3d

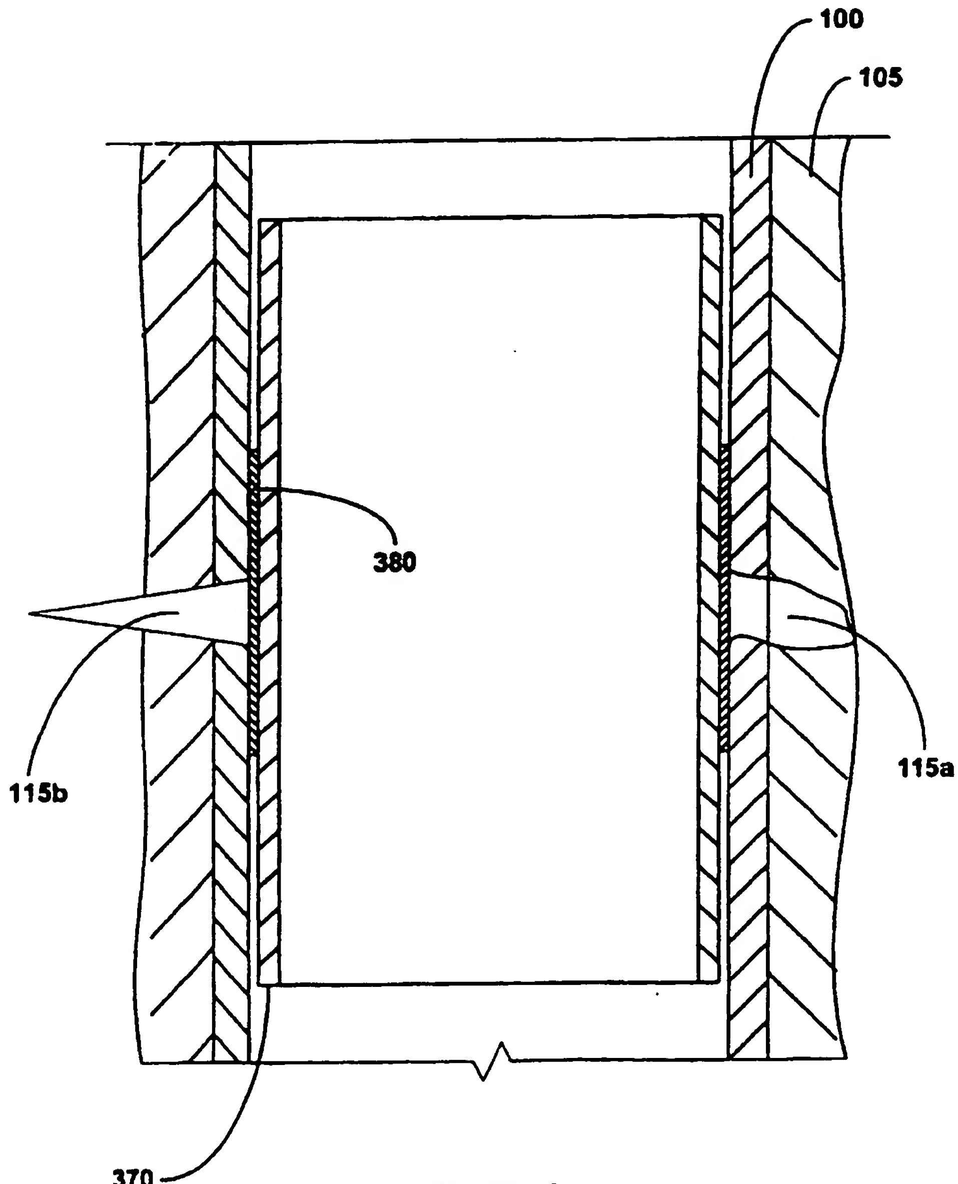
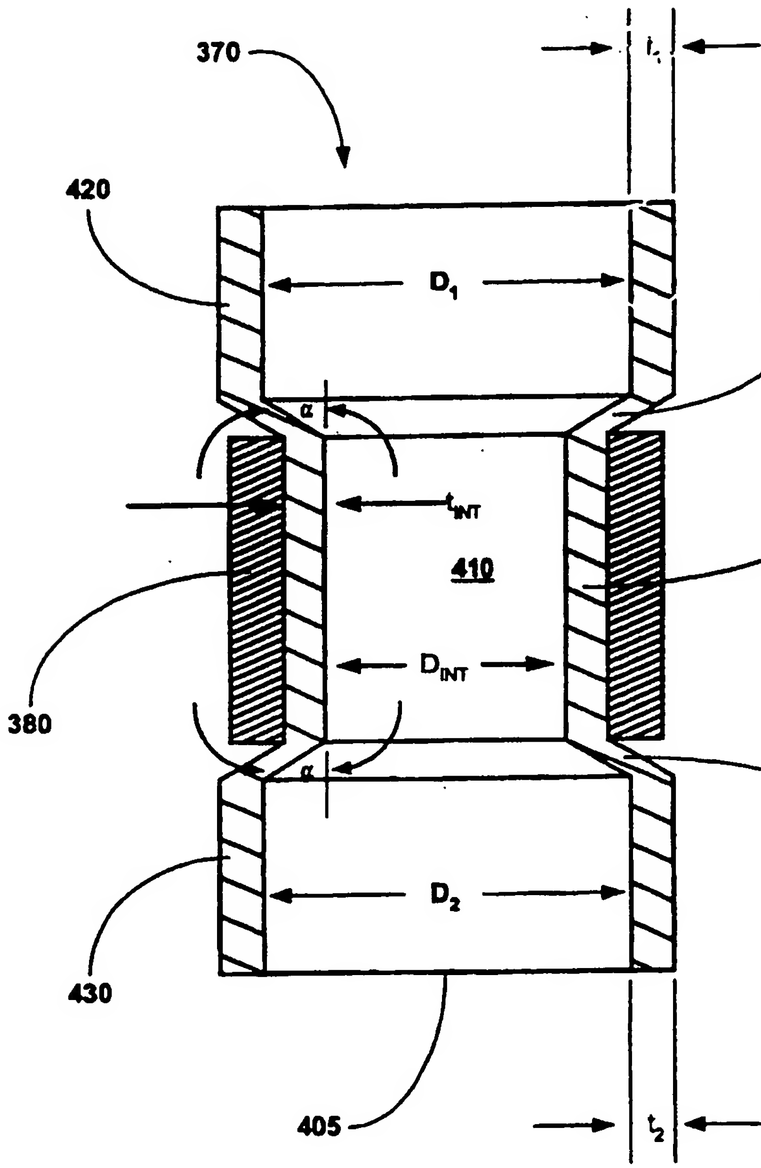


FIGURE 3e



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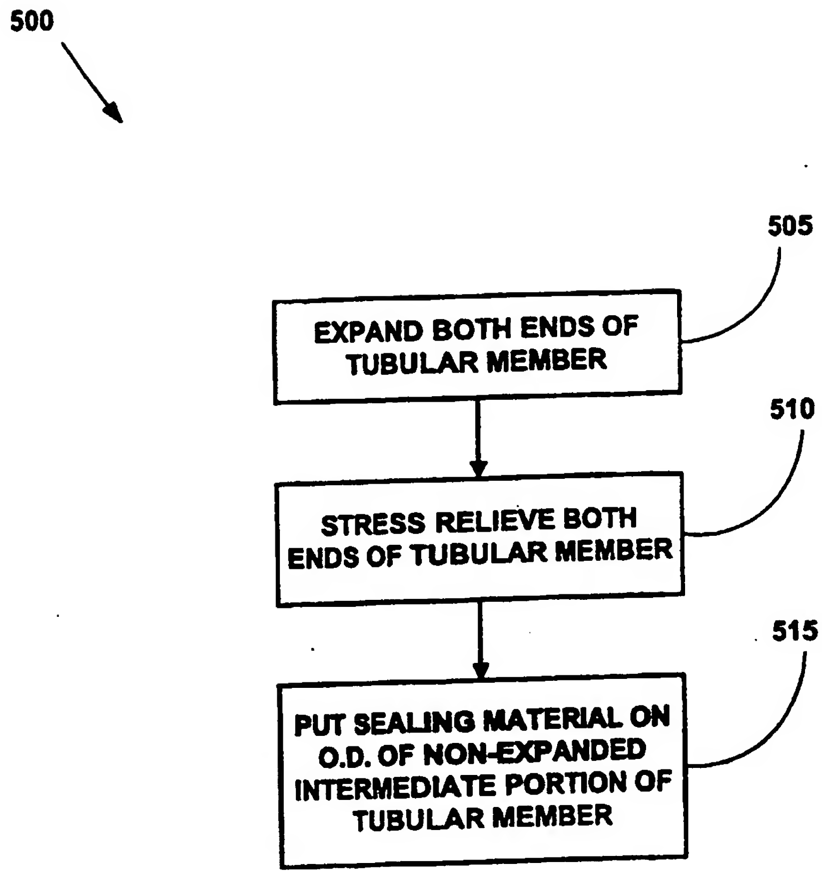
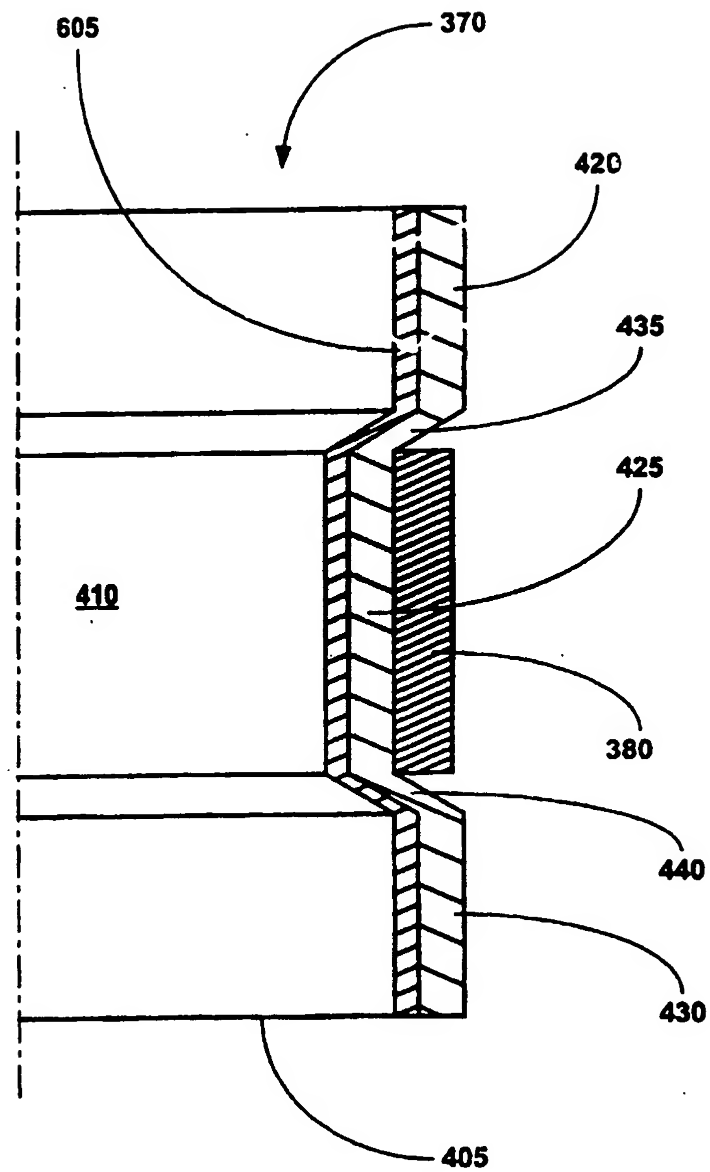

500
505
EXPAND BOTH ENDS OF TUBULAR MEMBER
510
STRESS RELIEVE BOTH ENDS OF TUBULAR MEMBER
515
PUT SEALING MATERIAL ON O.D. OF NON-EXPANDED INTERMEDIATE PORTION OF TUBULAR MEMBER

FIGURE 5



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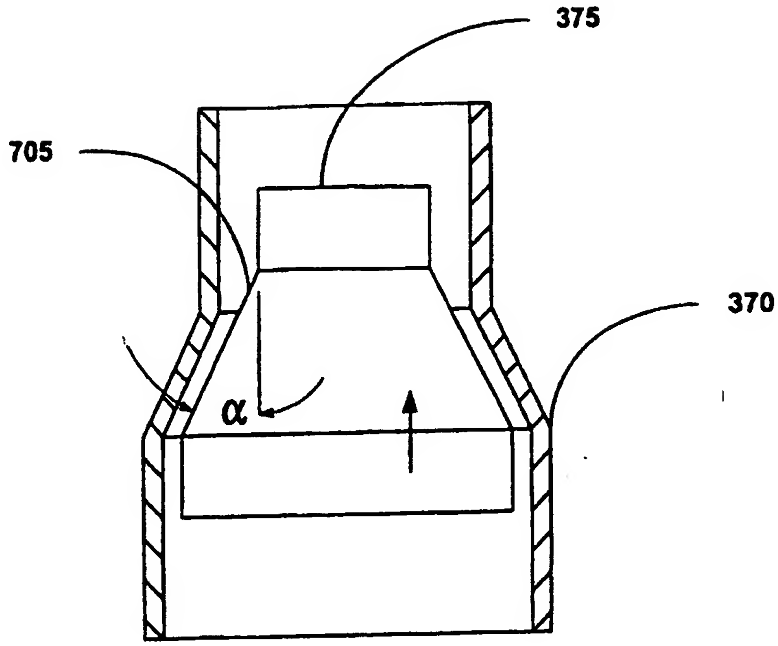

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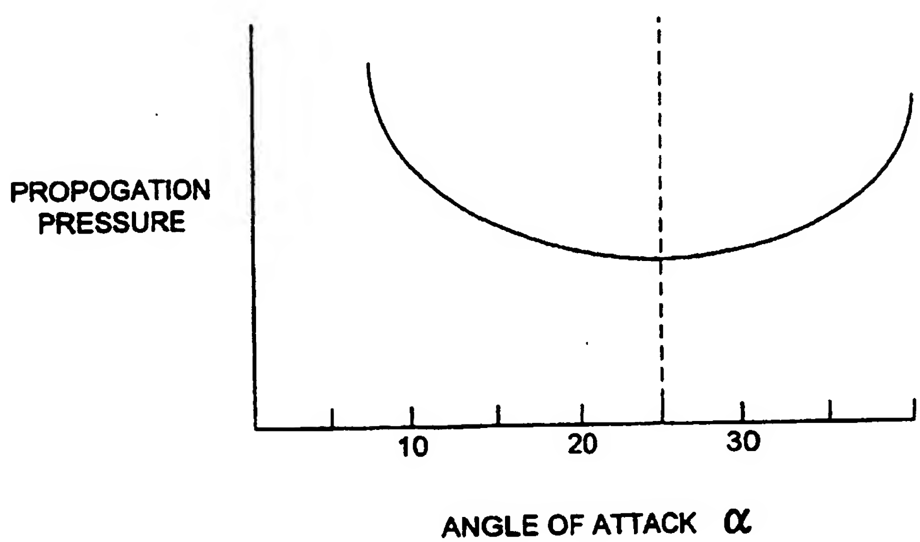

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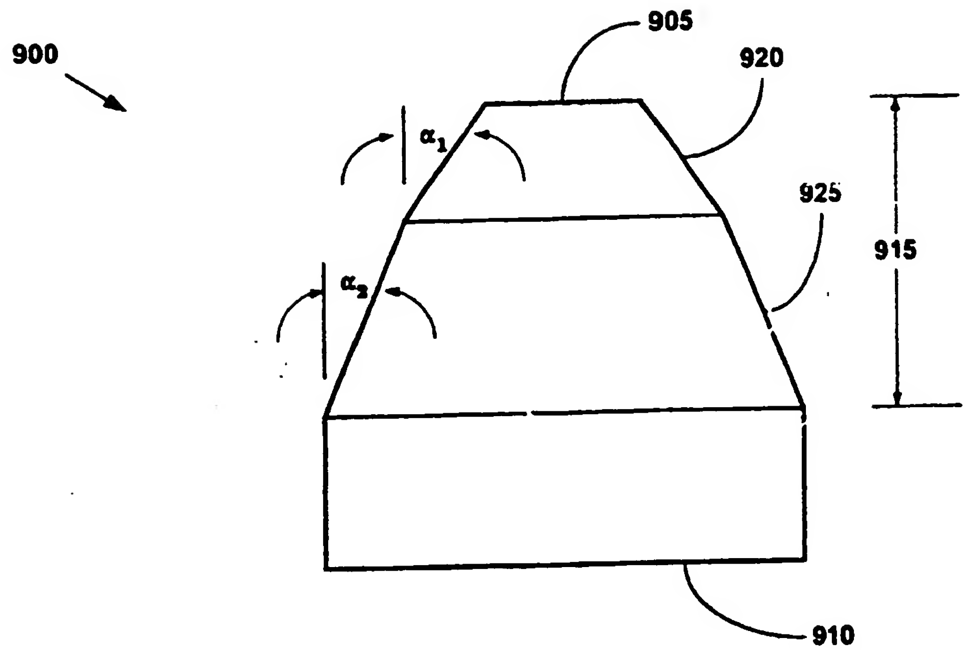

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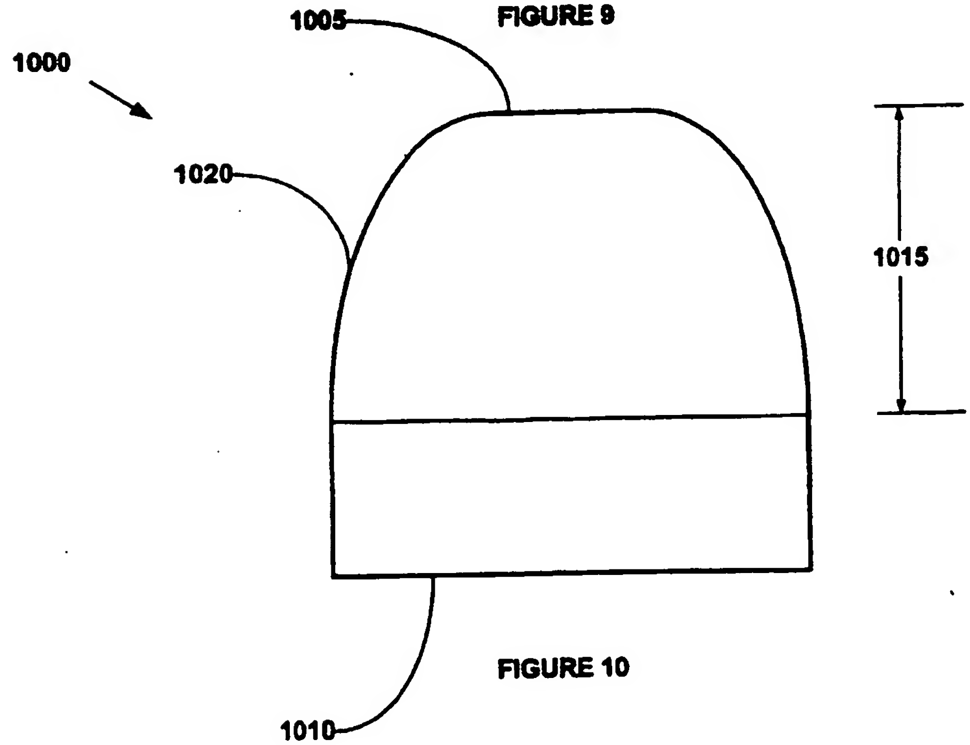

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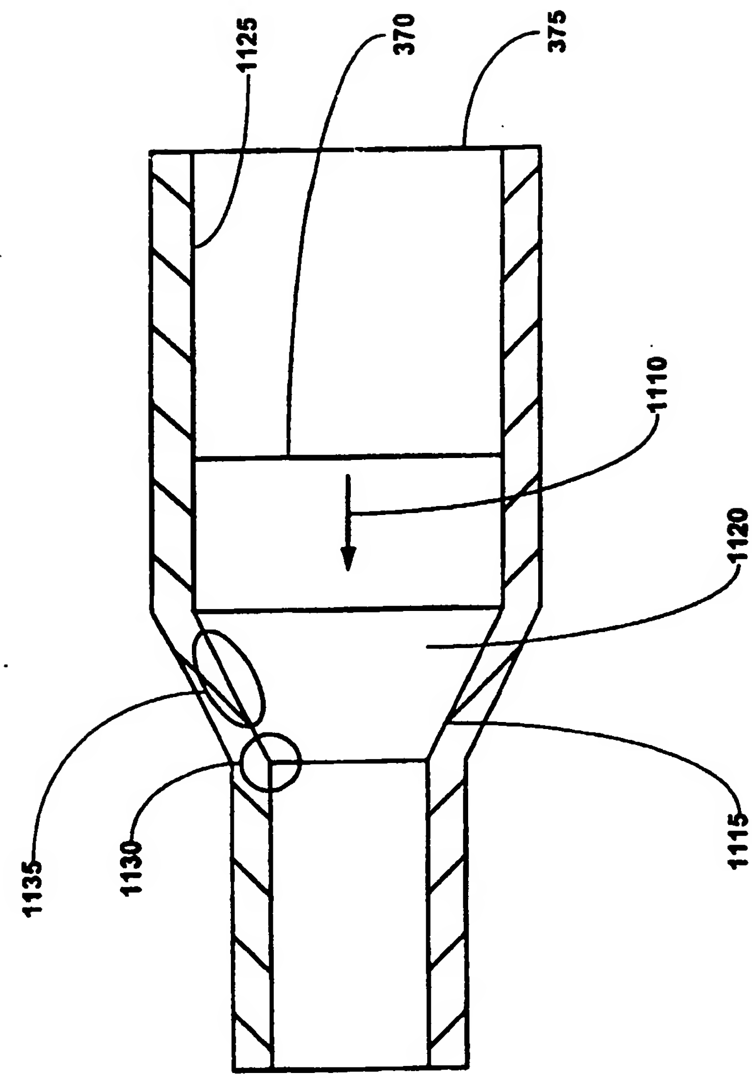

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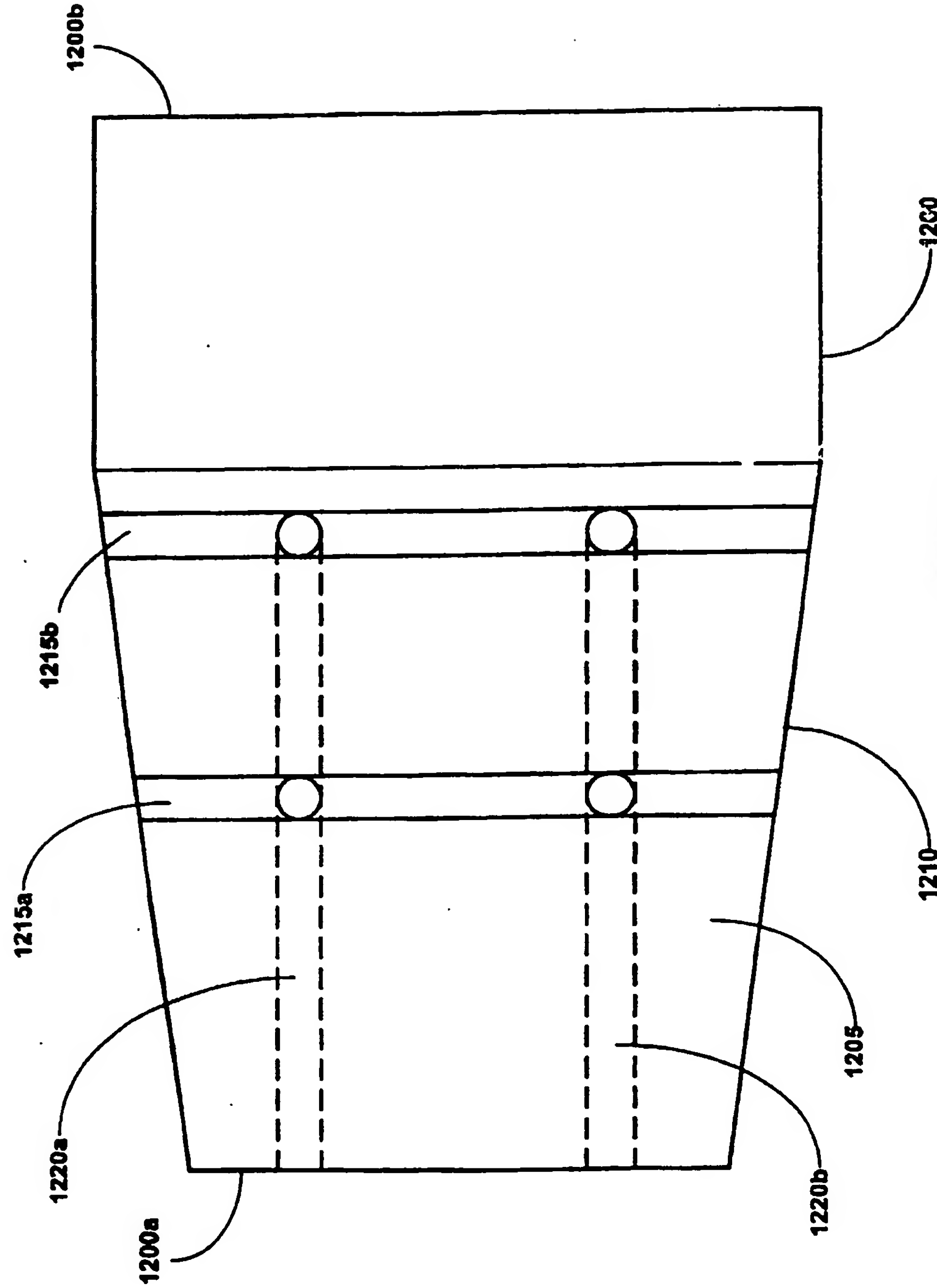

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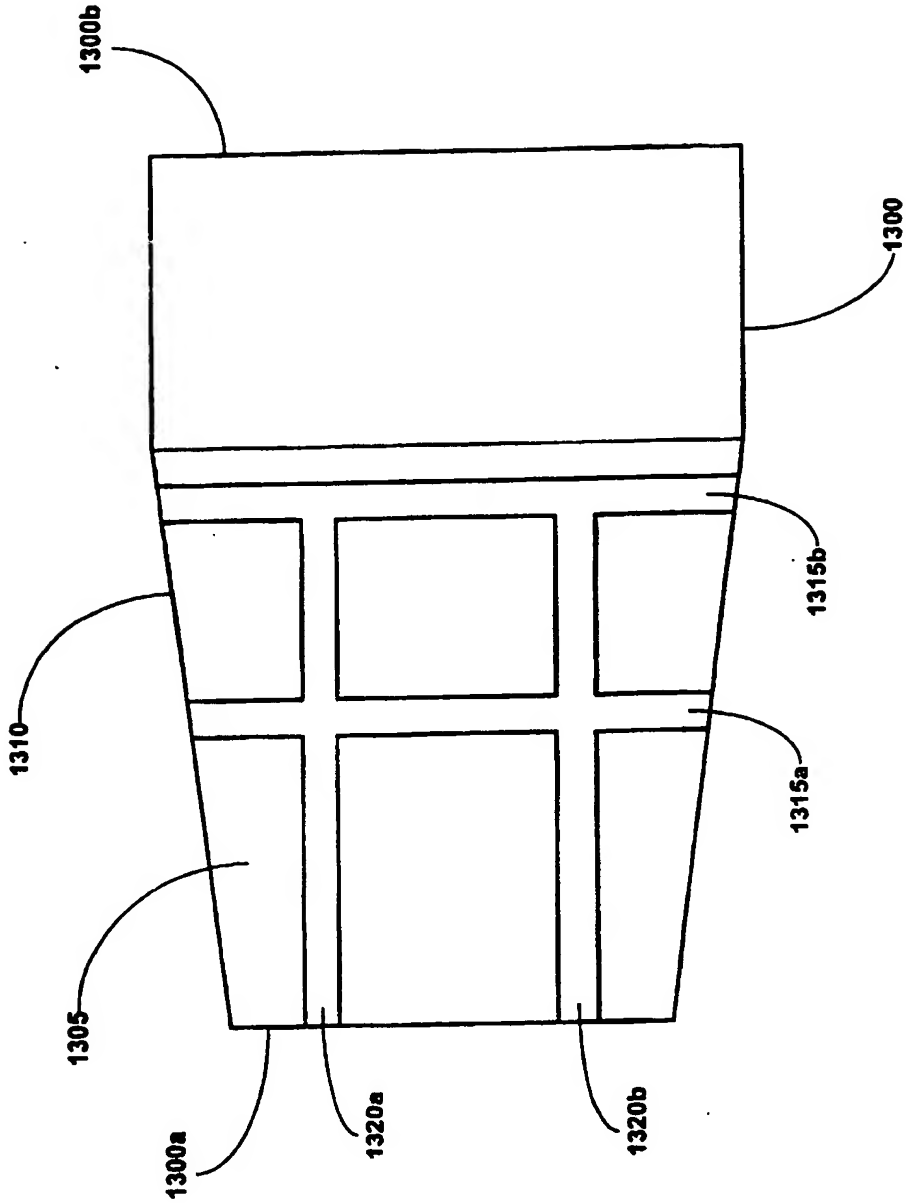

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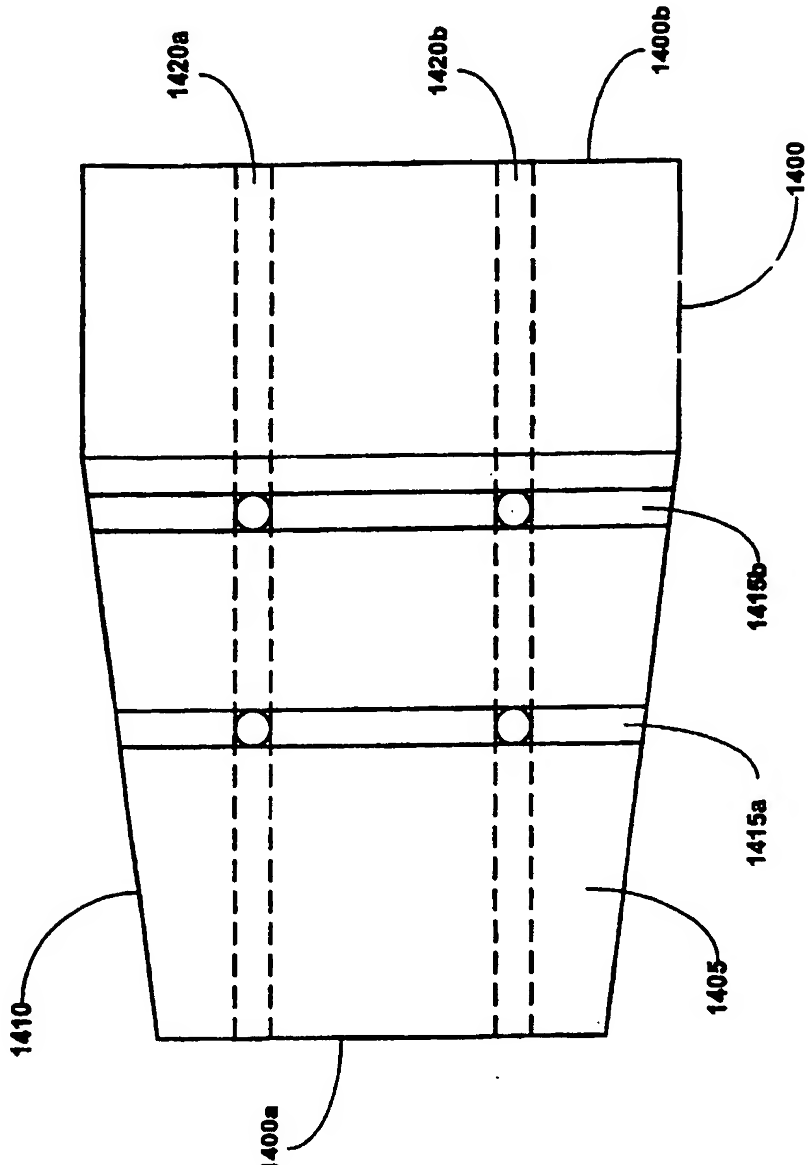
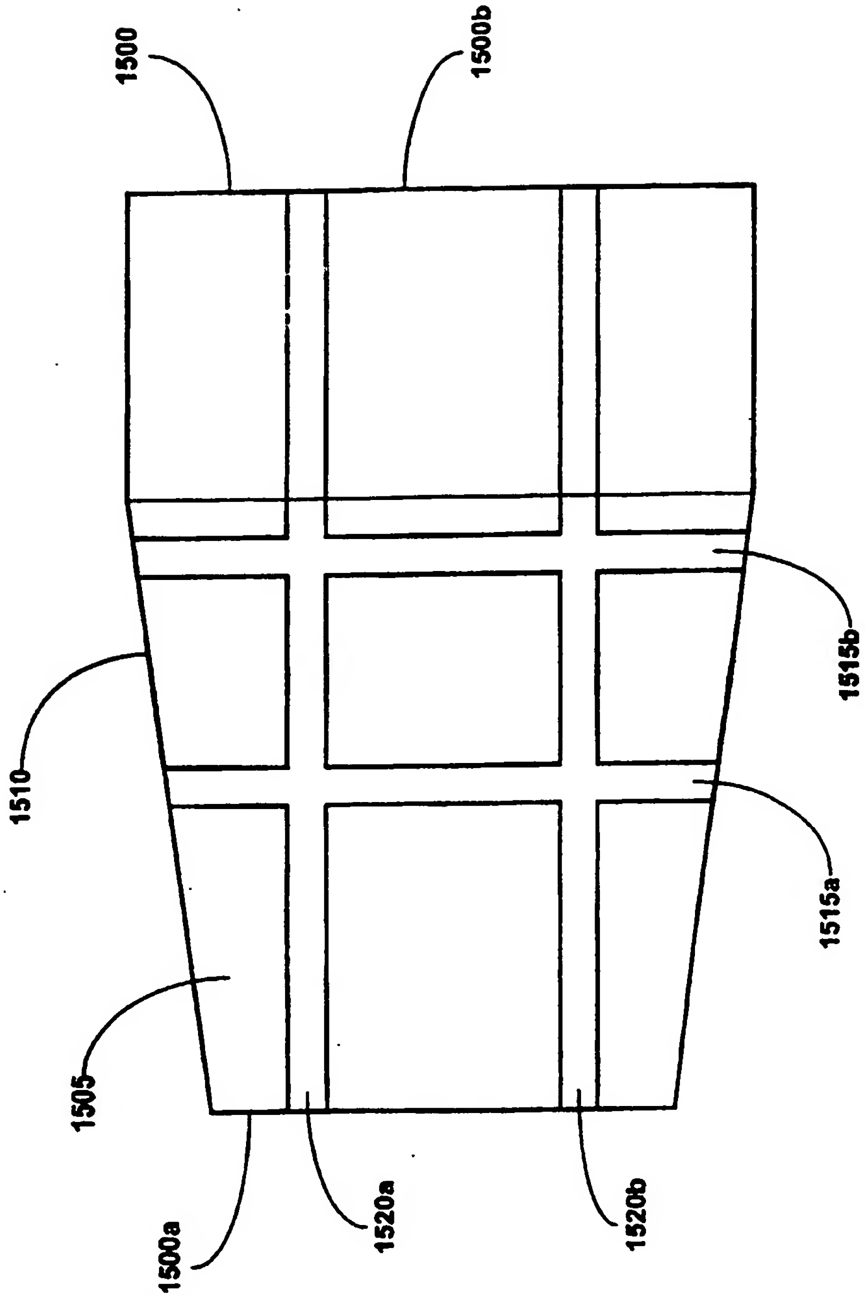


FIGURE 14



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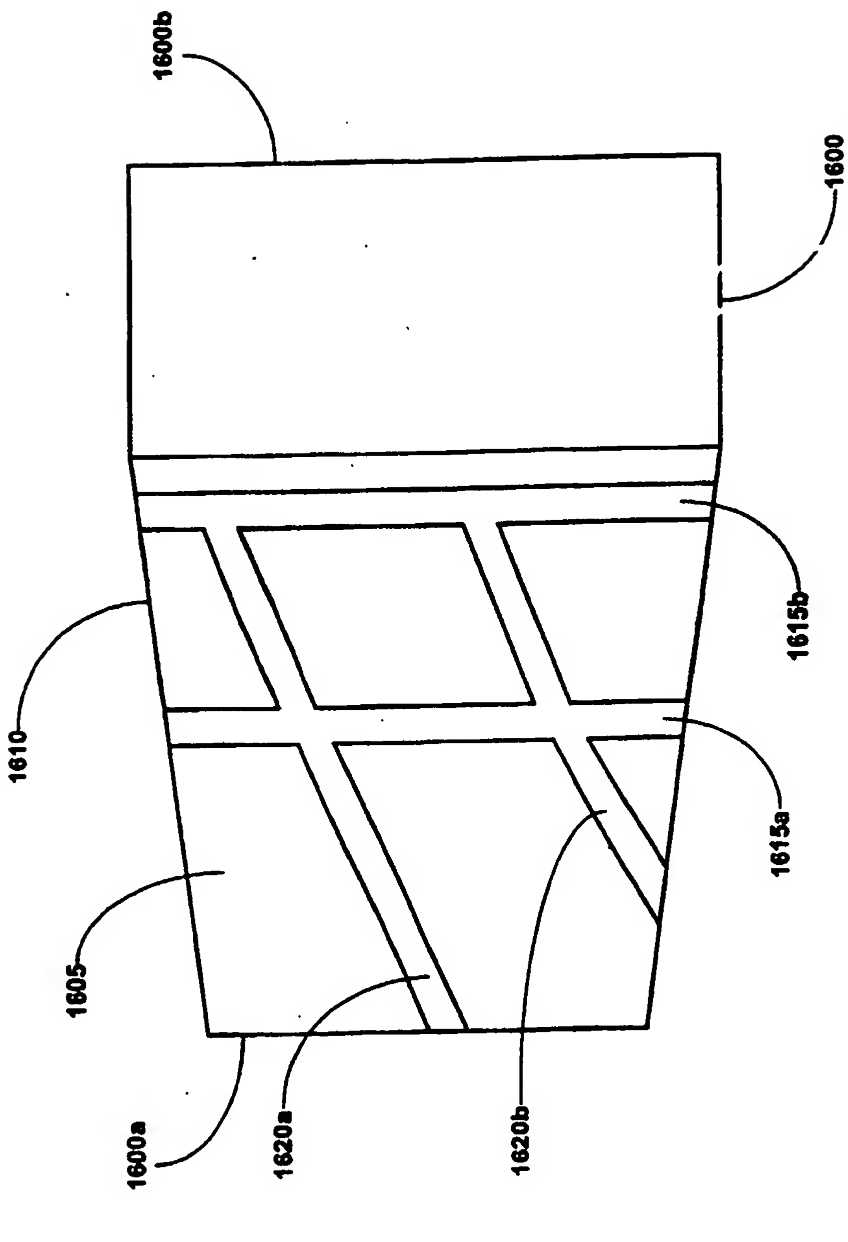

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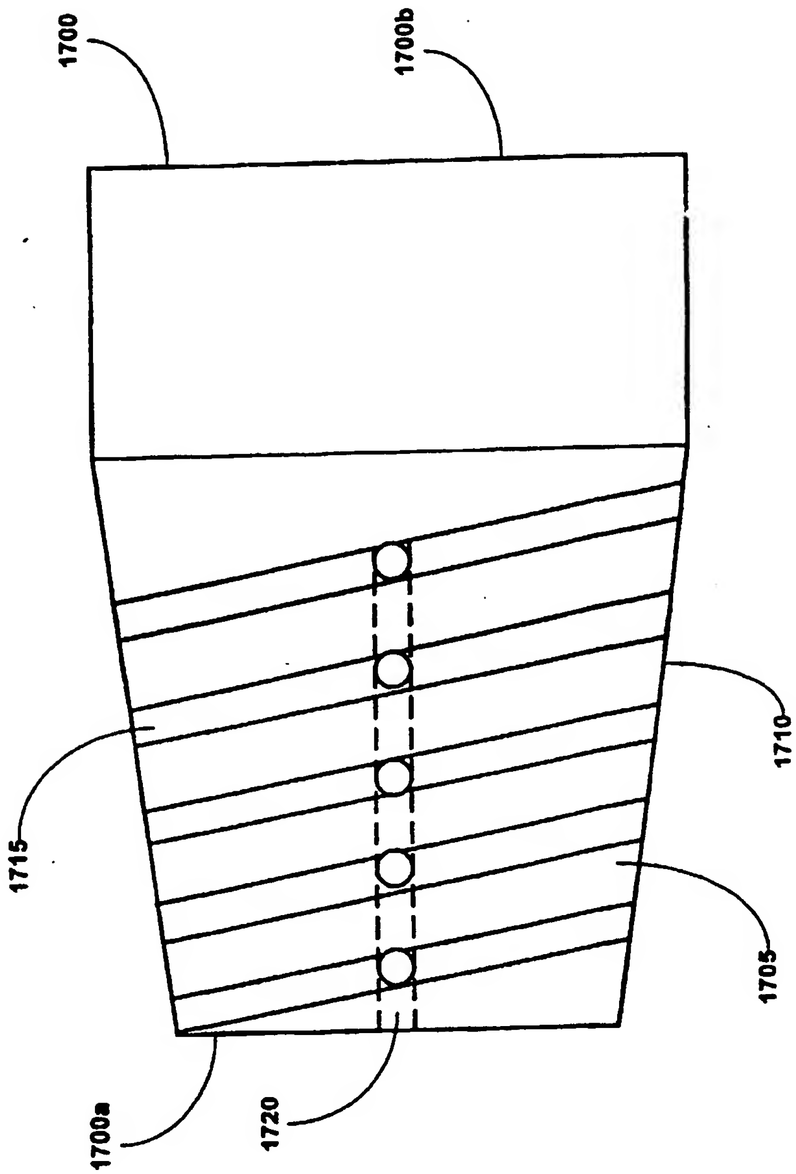

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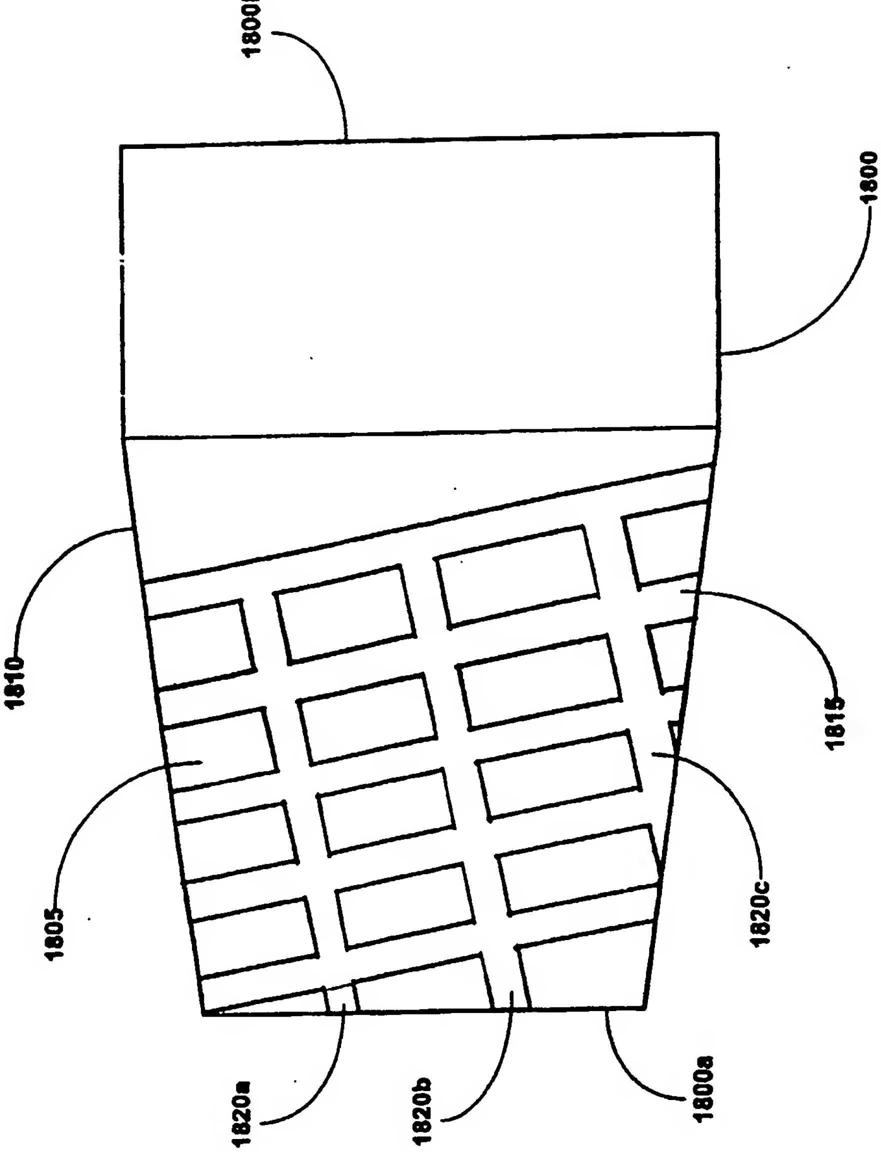

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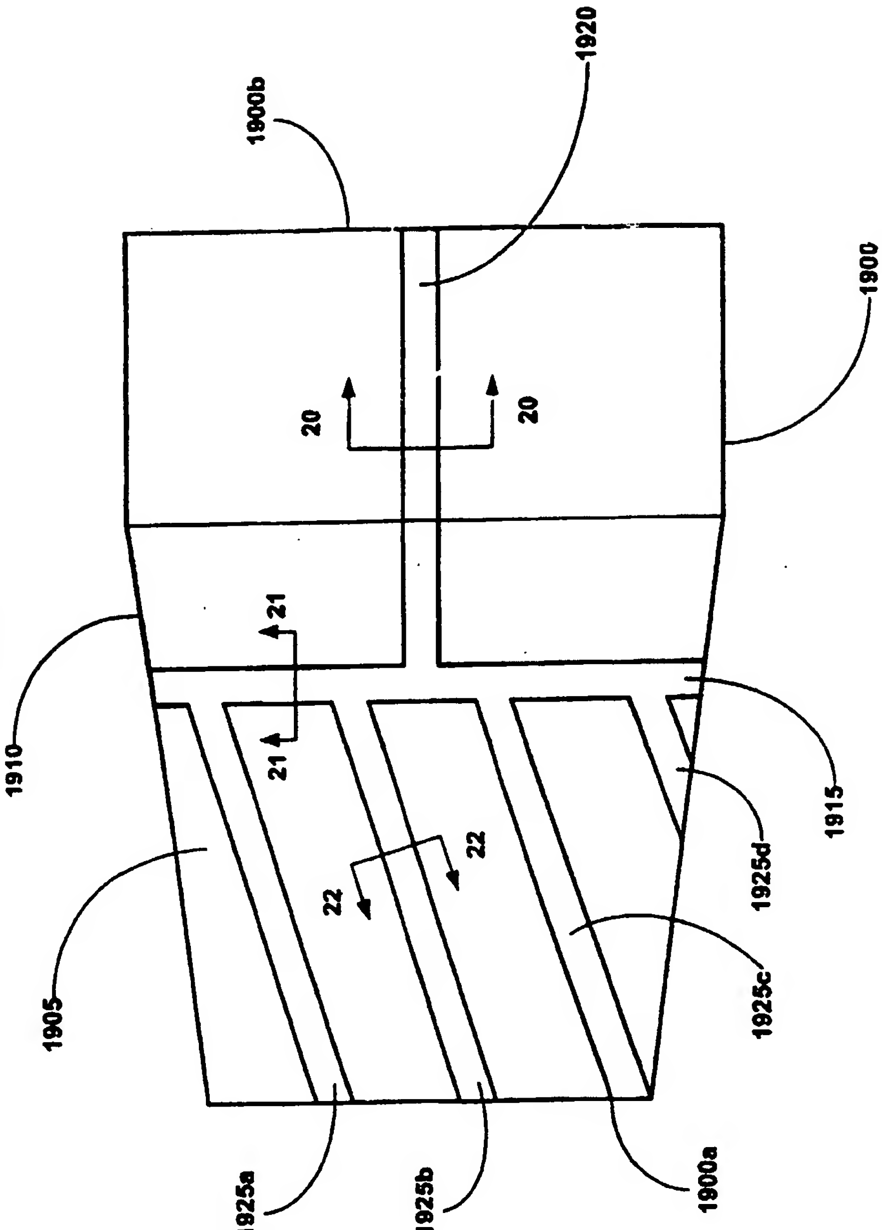

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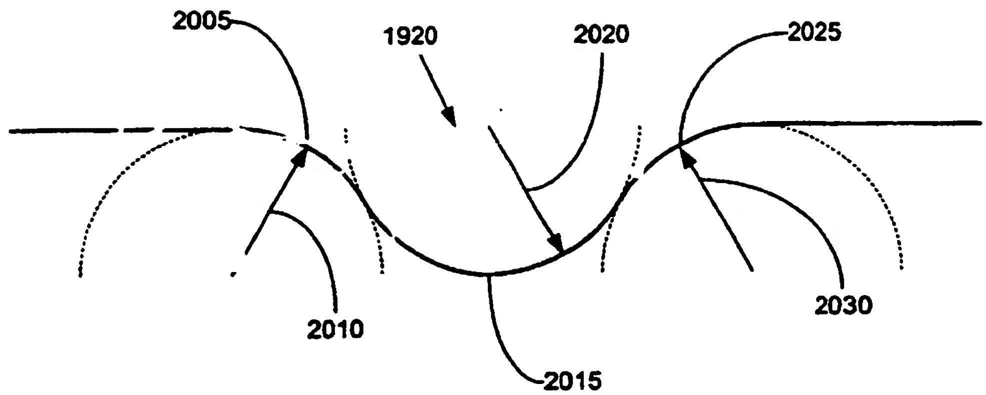
FIGURE 19



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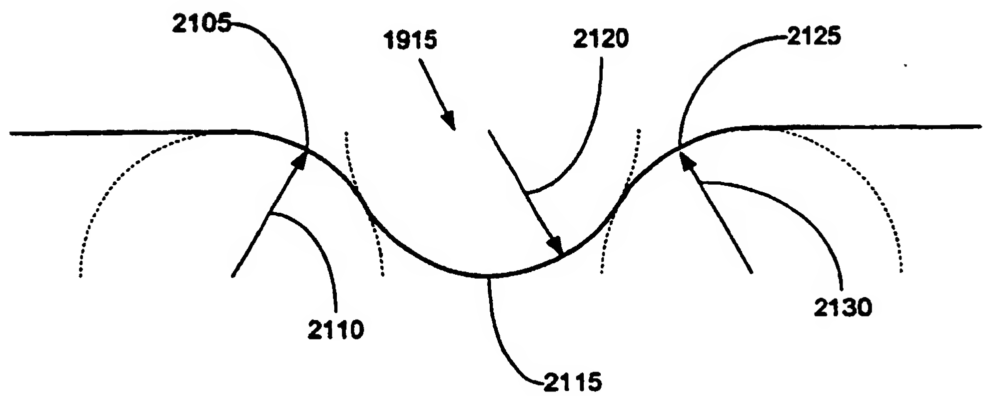

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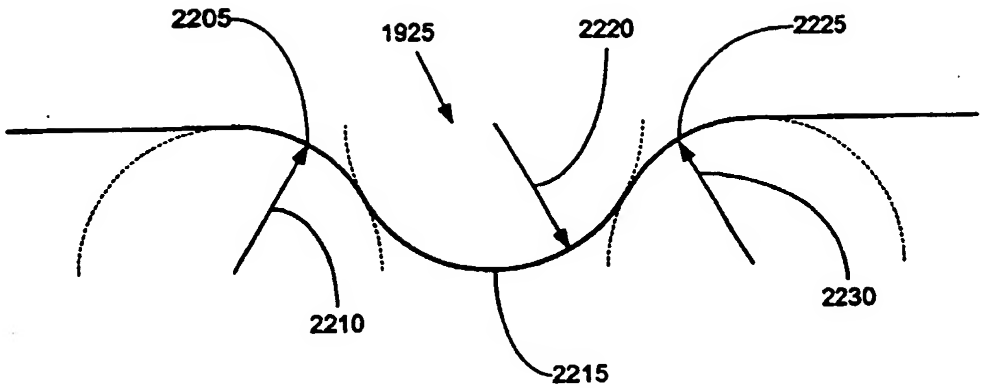

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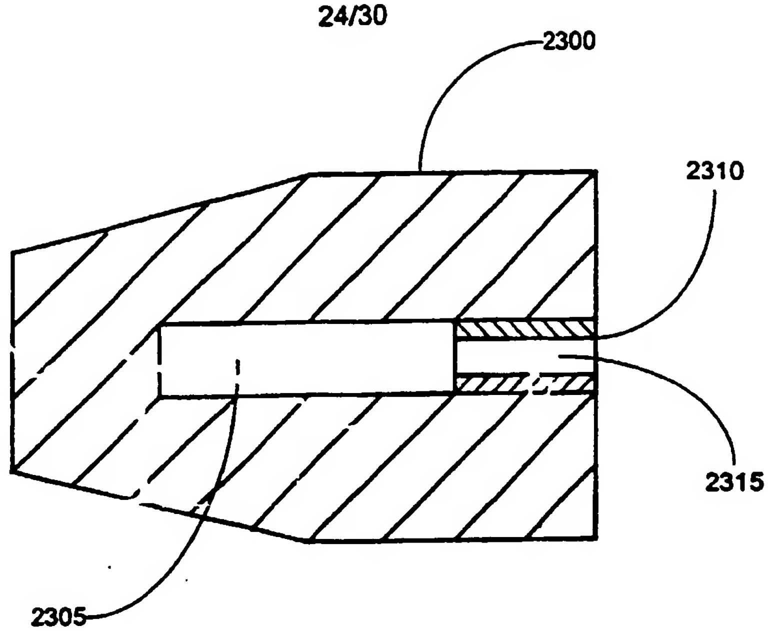

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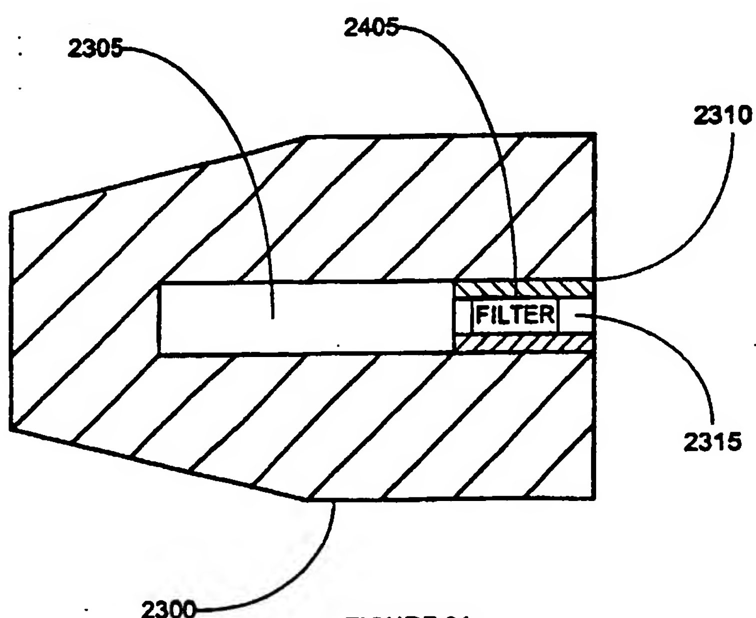

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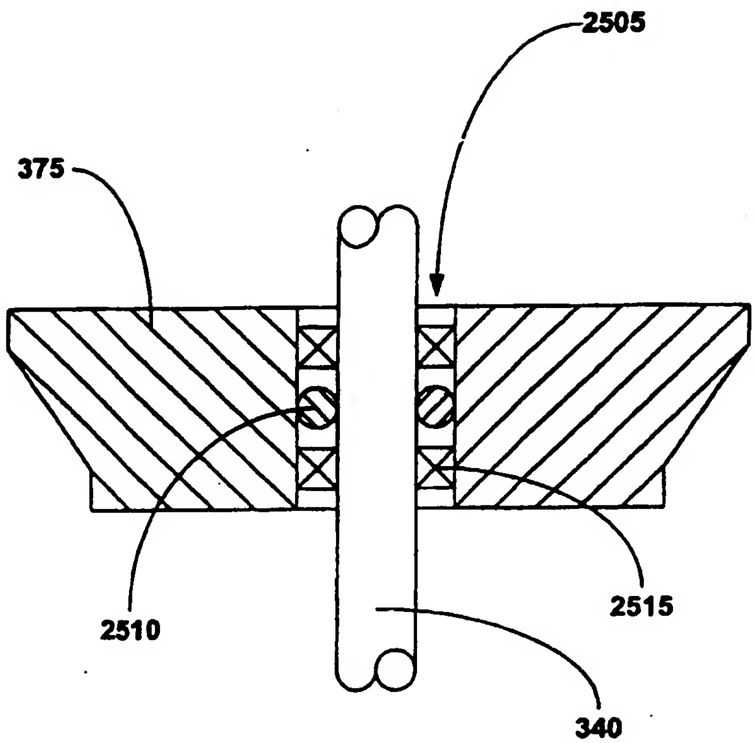

FIGURE 25

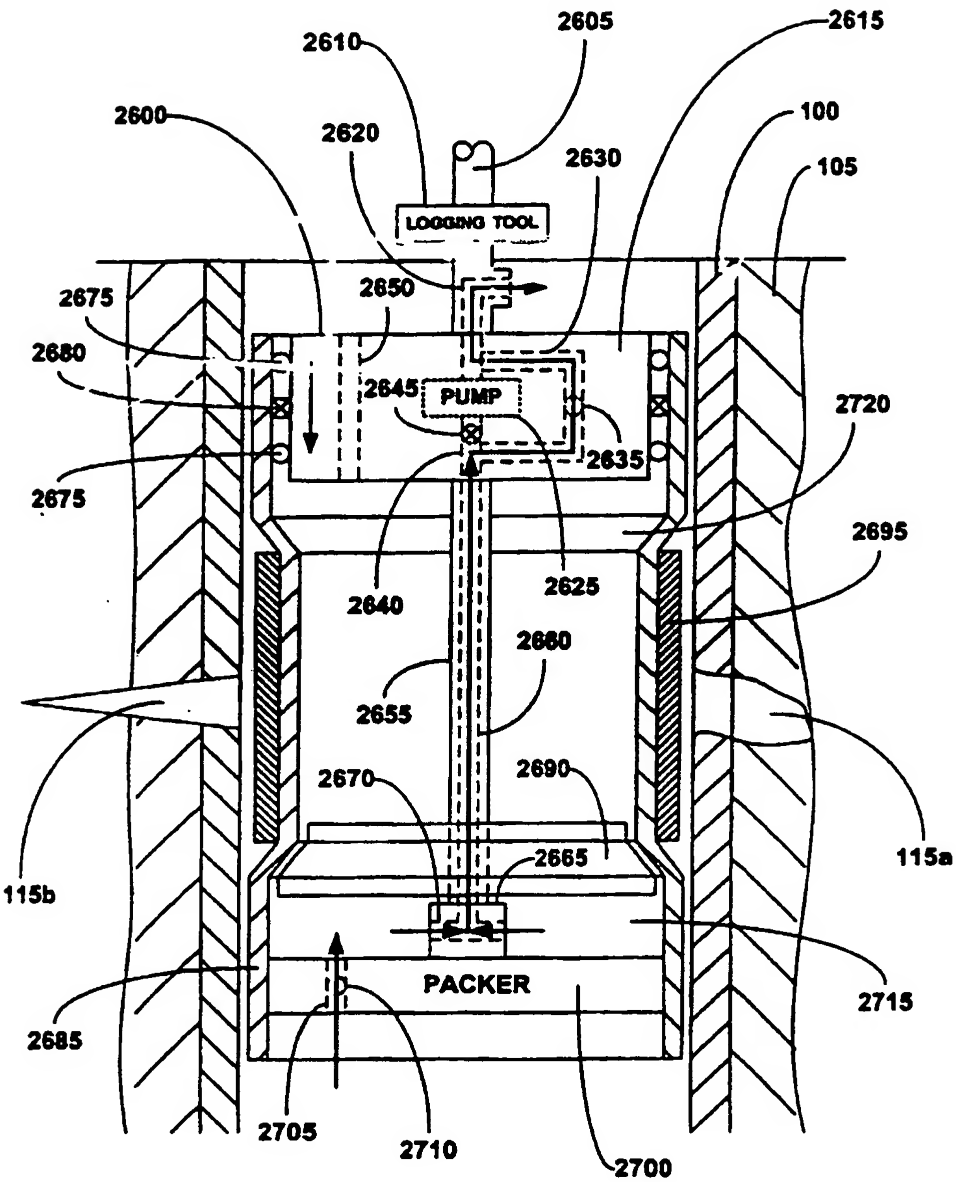

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FIGURE 26a

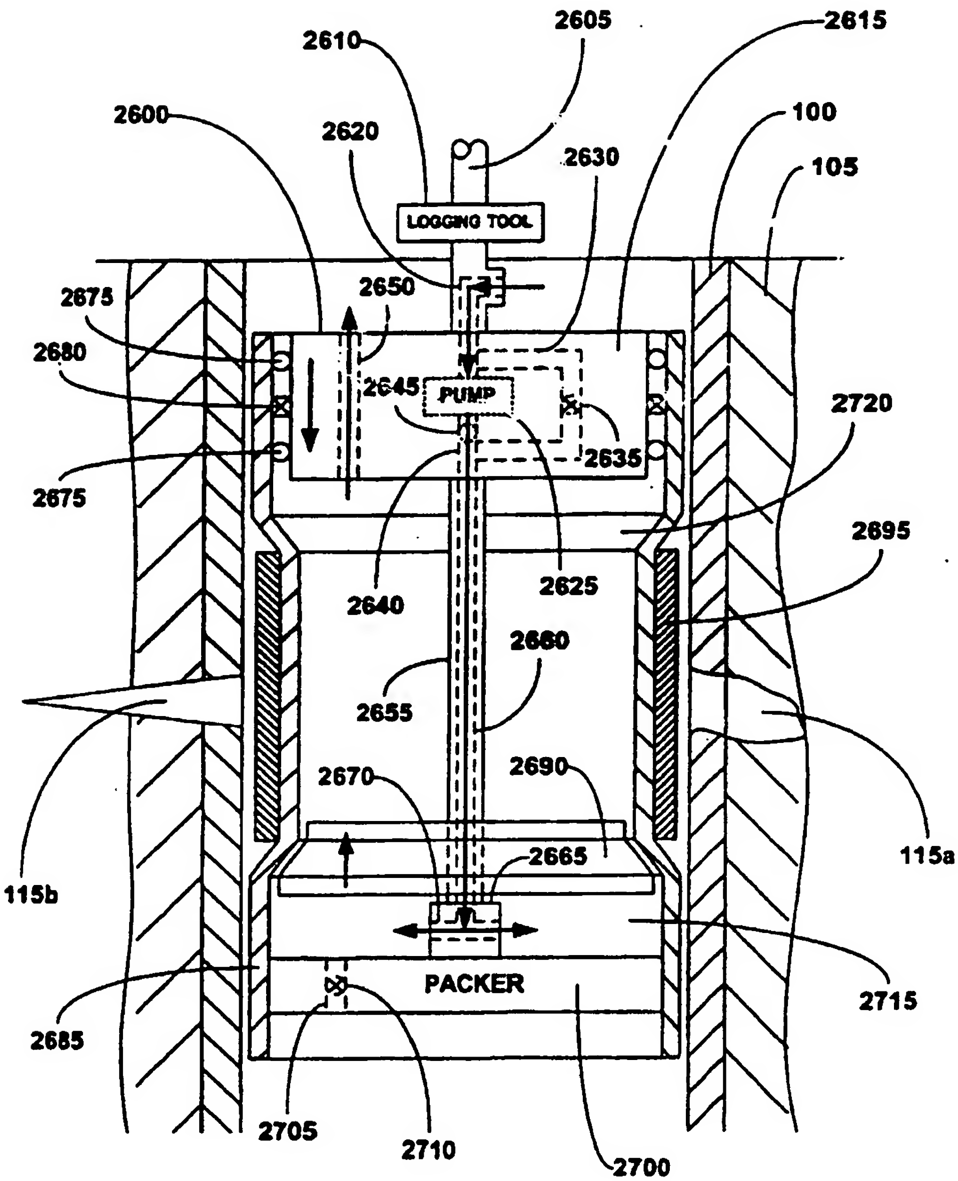
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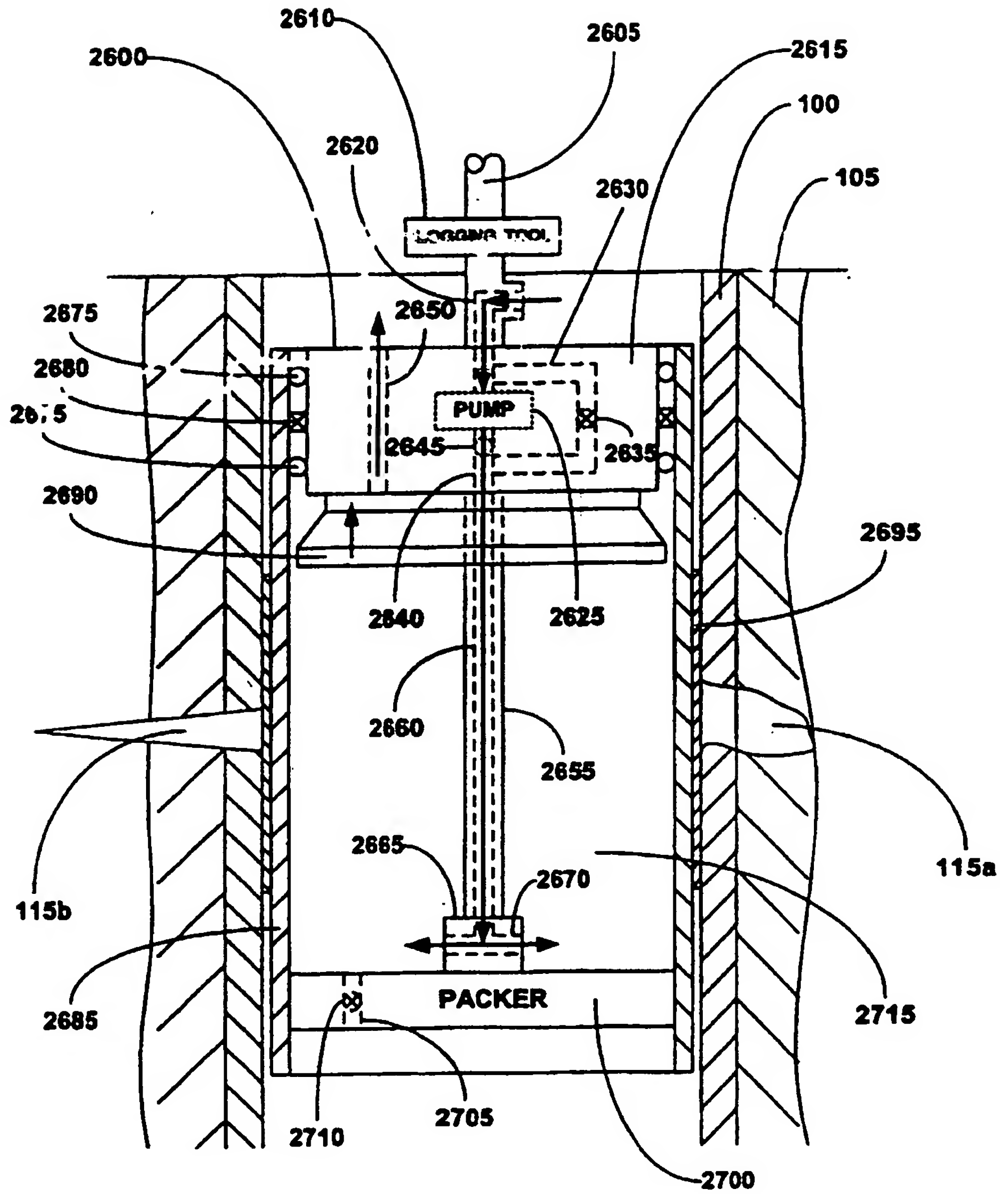
FIGURE 26b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PACKER
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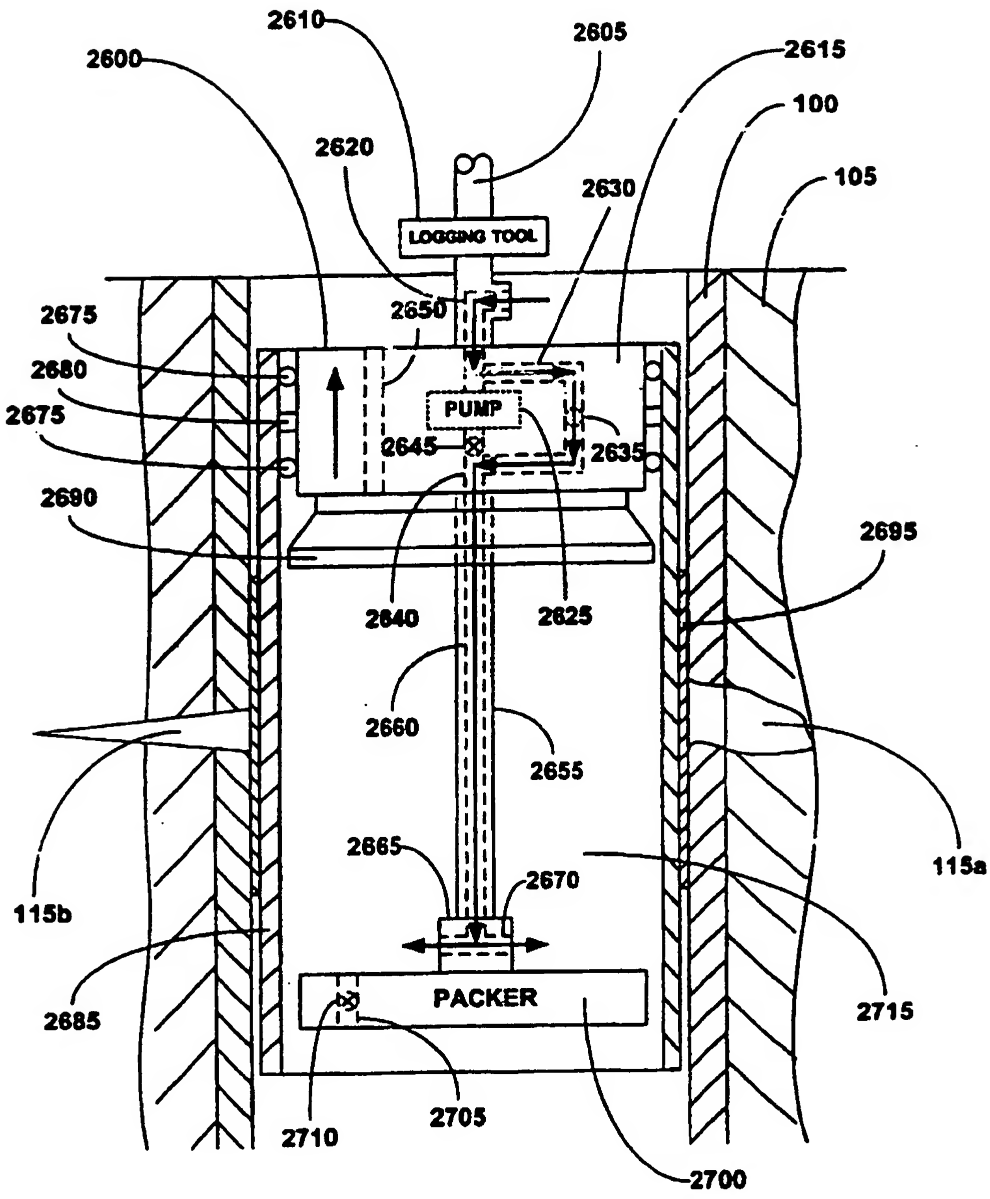
FIGURE 26c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PACKER
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FIGURE 26d

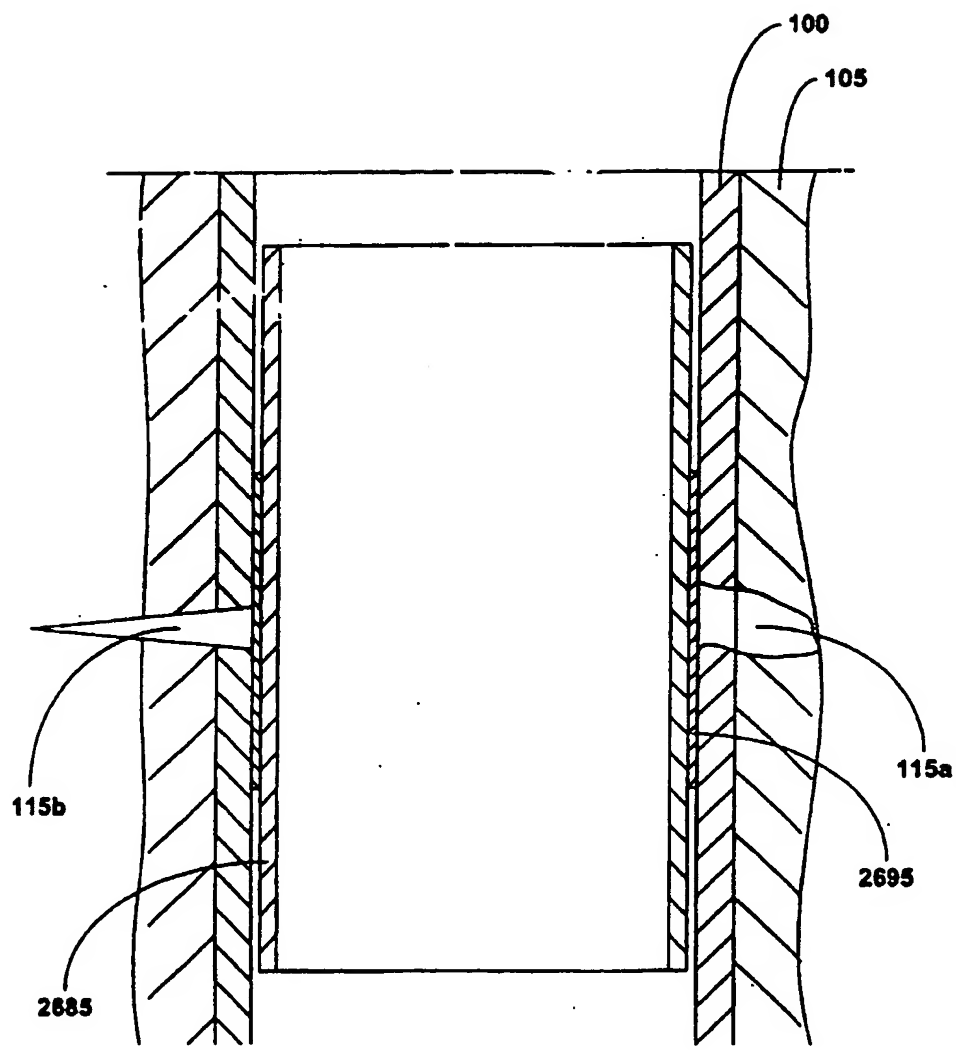

FIGURE 26e

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WELLBORE CASING REPAIR

Background of the Invention

This invention relates generally to wellbore casing repair, and in particular to repair of a wellbore casing that is formed using expandable tubing.

Conventionally, when a wellbore is created, a number of casings are installed in the borehole to prevent collapse of the borehole wall and to prevent undesired outflow of drilling fluid into the formation or inflow of fluid from the formation into the borehole. The borehole is drilled in intervals whereby a casing which is to be installed in a lower borehole interval is lowered through a previously installed casing of an upper borehole interval. As a consequence of this procedure the casing of the lower interval is of smaller diameter than the casing of the upper interval. Thus, the casings are in a nested arrangement with casing diameters decreasing in downward direction. Cement annuli are provided between the outer surfaces of the casings and the borehole wall to seal the casings from the borehole wall. As a consequence of this nested arrangement a relatively large borehole diameter is required at the upper part of the wellbore. Such a large borehole diameter involves increased costs due to heavy casing handling equipment, large drill bits and increased volumes of drilling fluid and drill cuttings. Moreover, increased drilling rig time is involved due to required cement pumping, cement hardening, required equipment changes due to large variations in hole diameters drilled in the course of the well, and the large volume of cuttings drilled and removed.

Conventionally, when an opening is formed in the sidewalls of an existing wellbore casing, whether through damage to the casing or because of an intentional perforation of the casing to facilitate production or a fracturing operation, it is often necessary to seal off the opening in the existing wellbore casing. Conventional methods of sealing off such openings are expensive and unreliable.

The present invention is directed to overcoming one or more of the limitations of the existing procedures for forming and repairing wellbores.

(

Summary of the Invention

According to the present invention there is provided a method of coupling a first tubular member to a second tubular member, wherein the outside diameter of the first tubular member is less than the inside diameter of the second tubular member, comprising:

positioning at least a portion of the first tubular member within the second tubular member;

pressurizing a portion of the interior of the first tubular member by pumping fluidic materials proximate the first tubular member into the portion of the interior of the first tubular member;

displacing an expansion cone within the interior of the first tubular member; and

lubricating the interface between the first tubular member and the expansion cone.

Preferably, the second tubular member is selected from the group consisting of a wellbore casing, a pipeline, and a structural support.

Preferably, lubricating includes coating the first tubular member with a lubricant.

Preferably, lubricating includes injecting a lubricating fluid into the trailing edge of the interface between the first tubular member and the expansion cone.

Preferably, lubricating includes:

coating the first tubular member with a first component of a lubricant; and

circulating a second component of the lubricant into contact with the coating on the first tubular member.

Preferably, the method includes sealing off a portion of the first tubular member.

According to another aspect of the present invention there is provided an apparatus for coupling a first tubular member to a second tubular member, wherein the outside diameter of the first tubular member is less than the inside diameter of the second tubular member, comprising:

means for positioning at least a portion of the first tubular member within the second tubular member;

means for pressurizing a portion of the interior of the first tubular member by pumping fluidic materials proximate the first tubular member into the portion of the interior of the first tubular member;

means for displacing an expansion cone within the interior of the first tubular member; and

means for lubricating the interface between the first tubular member and the expansion cone.

Preferably, the second tubular member is selected from the group consisting of a wellbore casing, a pipeline, and a structural support.

Preferably, the apparatus further includes means for coating the first tubular member with a lubricant.

Preferably, the apparatus further includes means for injecting a lubricating fluid into the trailing edge of the interface between the first tubular member and the expansion cone.

Preferably, the apparatus further includes:

means for coating the first tubular member with a first component of a lubricant; and

means for circulating a second component of the lubricant into contact with the coating on the first tubular member.

Preferably, the apparatus further includes means for sealing off a portion of the first tubular member.

Preferably, the first tubular member includes a sealing member coupled to the outer surface of the first tubular member.

Preferably, the first tubular member includes:

a first end having a first outer diameter;

an intermediate portion coupled to the first end having an intermediate outer diameter; and

a second end having a second outer diameter, and coupled to the intermediate portion;

wherein the first and second outer diameters are greater than the intermediate outer diameter.

Preferably, the first end, second end, and intermediate portion of the first tubular member have wall thicknesses t_1, t_2 and t_{INT} and inside diameters D_1, D_2 and D_{INT}; and wherein the relationship between the wall thicknesses t_1, t_2 and t_{INT}, the inside diameters D_1, D_2 and D_{INT}, the inside diameter D_{TUBE} of the second tubular member that the first tubular member will be inserted into, and the outer diameter D_{cone} of the expansion cone is given by the following expression:

$$D_{TUBE} - 2 * t_1 \geq D_1 \geq \frac{1}{t_1}\left[(t_1 - t_{INT}) * D_{CONE} + t_{INT} * D_{INT}\right]$$

where $t_1 = t_2$; and

$D_1 = D_2$.

Preferably, the first tubular member includes:

a sealing member coupled to the outside surface of the intermediate portion.

Preferably, the first tubular member includes:

a first transition portion coupled to the first end and the intermediate portion inclined at a first angle; and

a second transition portion coupled to the second end and the intermediate portion inclined at a second angle;

wherein the first and second angles range from 5 to 45 degrees.

Preferably, the expansion cone includes an expansion cone surface having an angle of attack ranging from 10 to 40 degrees.

Preferably, the expansion cone includes:

a first expansion cone surface having a first angle of attack; and

a second expansion cone surface having a second angle of attack;

wherein the first angle of attack is greater than the second angle of attack.

Preferably, the expansion cone includes an expansion cone surface having a substantially parabolic profile.

Preferably, the expansion cone includes an inclined surface including one or more lubricating grooves.

Preferably, the expansion cone includes one or more internal lubricating passages coupled to each of one or more lubricating grooves.

Preferably, the first tubular member includes a sealing member coupled to the outer surface of the first tubular member.

Preferably, the first tubular member includes:

a first end having a first outer diameter;

an intermediate portion coupled to the first end having an intermediate outer diameter; and

a second end having a second outer diameter, and coupled to the intermediate portion;

wherein the first and second outer diameters are greater than the intermediate outer diameter.

Preferably, the first end, second end, and intermediate portion of the first tubular member have wall thicknesses t_1, t_2 and t_{INT} and inside diameters D_1, D_2 and D_{INT}; and wherein the relationship between the thicknesses t_1, t_2 and t_{INT}, the inside diameter D_1, D_2 and D_{INT}; the inside diameter D_{TUBE} of the second tubular member that the first tubular member will be inserted into, and the outside diameter D_{cone} of the expansion cone is given by the following expression:

$$D_{TUBE} - 2 * t_1 \geq D_1 \geq \frac{1}{t_1}\left[(t_1 - t_{INT}) * D_{CONE} + t_{INT} * D_{INT}\right]$$

where $t_1 = t_2$; and

$D_1 = D_2$.

Preferably, the first tubular member includes a sealing member coupled to the outside surface of the intermediate portion.

Preferably, the first tubular member includes:

a first transition portion coupled to the first end and the intermediate portion inclined at a first angle; and

a second transition portion coupled to the second end and the intermediate portion inclined at a second angle;

wherein the first and second angles range from 5 to 45 degrees.

Preferably, the expansion cone includes an expansion cone surface having an angle of attack ranging from 10 to 40 degrees.

Preferably, the expansion cone includes:

a first expansion cone surface having a first angle of attack; and

a second expansion cone surface having a second angle of attack;

wherein the first angle of attack is greater than the second angel of attack.

Preferably, the expansion cone includes an expansion cone surface having a substantially parabolic profile.

Preferably, the expansion cone includes an inclined surface including one or more lubricating grooves.

Preferably, the expansion cone includes one or more internal lubricating passages coupled to each of the lubricating grooves.

Brief Description of the Drawings

FIG. 1 is a fragmentary cross-sectional view of a wellbore casing including one or more openings.

FIG. 2 is a flow chart illustration of a method for repairing the wellbore casing of FIG. 1.

FIG. 3a is a fragmentary cross-sectional view of the placement of a repair apparatus within the wellbore casing of FIG. 1 wherein the expandable tubular member of the apparatus is positioned opposite the openings in the wellbore casing.

FIG. 3b is a fragmentary cross-sectional view of the radial expansion of the expandable tubular of the apparatus of FIG. 3a.

FIG. 3c is a fragmentary cross-sectional view of the completion of the radial expansion of the expandable tubular of the apparatus of FIG. 3b.

FIG. 3d is a fragmentary cross-sectional view of the removal of the repair apparatus from the repaired wellbore casing of FIG. 3c.

FIG. 3e is a fragmentary cross-sectional view of the repaired wellbore casing of FIG. 3d.

FIG. 4 is a cross-sectional illustration of the expandable tubular of the apparatus of FIG. 3a.

FIG. 5 is a flow chart illustration of a method for fabricating the expandable tubular of the apparatus of FIG. 3a.

FIG. 6 is a fragmentary cross-sectional illustration of the expandable tubular of FIG. 4.

FIG. 7 is a fragmentary cross-sectional illustration of an expansion cone expanding a tubular member.

FIG. 8 is a graphical illustration of the relationship between propagation pressure and the angle of attack of the expansion cone.

FIG. 9 is an illustration of an expansion cone optimally adapted to radially expand the expandable tubular member of FIG. 4.

FIG. 10 is an illustration of an expansion cone optimally adapted to radially expand the expandable tubular member of FIG. 4.

FIG. 11 is a fragmentary cross-sectional illustration of the lubrication of the interface between an expansion cone and a tubular member during the radial expansion process.

FIG. 12 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 13 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 14 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 15 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 16 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 17 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 18 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 19 is an illustration of an expansion cone including a system for lubricating the interface between the expansion cone and a tubular member during the radial expansion of the tubular member.

FIG. 20 is a cross-sectional illustration of the first axial groove of the expansion cone of FIG. 19.

FIG. 21 is a cross-sectional illustration of the circumferential groove of the expansion cone of FIG. 19.

FIG. 22 is a cross-sectional illustration of one of the second axial grooves of the expansion cone of FIG. 19.

FIG. 23 is a cross sectional illustration of an expansion cone including internal flow passages having inserts for adjusting the flow of lubricant fluids.

FIG. 24 is a cross sectional illustration of the expansion cone of FIG. 23 further including an insert having a filter for filtering out foreign materials from the lubricant fluids.

FIG. 25 is a fragmentary cross sectional illustration of the expansion cone of the repair apparatus of FIG. 3a.

FIG. 26a is a fragmentary cross-sectional view of the placement of a repair apparatus within the wellbore casing of FIG. 1 wherein the expandable tubular member of the apparatus is positioned opposite the openings in the wellbore casing.

FIG. 26b is a fragmentary cross-sectional view of the radial expansion of the expandable tubular of the apparatus of FIG. 26a.

FIG. 26c is a fragmentary cross-sectional view of the completion of the radial expansion of the expandable tubular of the apparatus of FIG. 26b.

FIG. 26d is a fragmentary cross-sectional view of the removal of the repair apparatus from the repaired wellbore casing of FIG. 26c.

FIG. 26e is a fragmentary cross-sectional view of the repaired wellbore casing of FIG. 26d.

Detailed Description

Referring initially to FIG. 1, a wellbore casing 100 having an outer annular layer 105 of a sealing material is positioned within a subterranean formation 110. The wellbore casing 100 may be positioned in any orientation from vertical to horizontal. The wellbore casing 100 further includes one or more openings 115a and 115b. The openings 115 may, for example, be the result of: defects in the wellbore casing 100, intentional perforations of the casing to facilitate production, thin walled sections of casing caused by drilling and/or wireline wear, or fracturing operations. As will be recognized by persons having ordinary skill in the art, such openings 115 in a wellbore 100 can seriously adversely impact the subsequent production of oil and gas from the subterranean formation 110 unless they are sealed off. More generally, the wellbore casing 115 may include thin walled sections that need cladding in order to prevent a catastrophic failure.

Referring to FIG. 2, a method 200 for repairing a defect in a wellbore casing using a repair apparatus having a logging tool, a pump, an expansion cone, and an expandable tubular member includes the steps of: (1) positioning the repair apparatus within the wellbore casing in step 205; (2) locating the defect in the wellbore casing using the logging tool of the repair apparatus in step 210; (3) positioning the expandable tubular member in opposition to the defect in the wellbore casing in step 215; and (4) radially expanding the expandable tubular member into intimate contact with the wellbore casing by pressurizing a portion of the expandable tubular member using the pump and extruding the expandable tubular member off of the expansion cone in step 220. In this manner, defects in a

wellbore casing are repaired by a compact and self-contained repair apparatus that is positioned downhole. More generally, the repair apparatus is used to repair defects in wellbore casings, pipelines, and structural supports.

As illustrated in FIG. 3a, in step 205, a repair apparatus 300 is positioned within the wellbore casing 100.

The repair apparatus 300 includes a first support member 305, a logging tool 310, a housing 315, a first fluid conduit 320, a pump 325, a second fluid conduit 330, a third fluid conduit 335, a second support member 340, a fourth fluid conduit 345, a third support member 350, a fifth fluid conduit 355, sealing members 360, a locking member 365, an expandable tubular 370, an expansion cone 375, and a sealing member 380.

The first support member 305 is preferably coupled to the logging tool 310 and the housing 315. The first support member 305 is preferably adapted to be coupled to and supported by a conventional support member such as, for example, a wireline, coiled tubing, or a drill string. The first support member 305 preferably has a substantially annular cross section in order to provide one or more conduits for conveying fluidic materials from the repair apparatus 300. The first support member 305 is further preferably adapted to convey electrical power and communication signals to the logging tool 310, the pump 325, and the locking member 365.

The logging tool 310 is preferably coupled to the first support member 305. The logging tool 310 is preferably adapted to detect defects in the wellbore casing 100. The logging tool 310 may be any number of conventional commercially available logging tools suitable for detecting defects in wellbore casings, pipelines, or structural supports. The logging tool 310 is a CAST logging tool, available from Halliburton(RTM) Energy Services in order to optimally provide detection of defects in the wellbore casing 100. The logging tool 310 is contained within the housing 315 in order to provide an repair apparatus 300 that is rugged and compact.

The housing 315 is preferably coupled to the first support member 305, the second support member 340, the sealing members 360, and the locking member 365. The housing 315 is preferably releasably coupled to the tubular member 370. The

housing 315 is further preferably adapted to contain and/or support the logging tool 310 and the pump 325.

The first fluid conduit 320 is preferably fluidicly coupled to the inlet of the pump 325 and the exterior region above the housing 315. The first fluid conduit 320 may be contained within the first support member 305 and the housing 315. The first fluid conduit 320 is preferably adapted to convey fluidic materials such as, for example, drilling muds, water, and lubricants at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 500 gallons/minute in order to optimally propagate the expansion cone 375.

The pump 325 is fluidicly coupled to the first fluid conduit 320 and the second fluid conduit 330. The pump 325 is further preferably contained within and supported by the housing 315. Alternatively, the pump 325 may be positioned above the housing 315. The pump 325 is preferably adapted to convey fluidic materials from the first fluid conduit 320 to the second fluid conduit 330 at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 500 gallons/minute in order to optimally provide the operating pressure for propagating the expansion cone 375. The pump 325 may be any number of conventional commercially available pumps. The pump 325 is a flow control pump out section for dirty fluids, available from Halliburton(RTM) Energy Services in order to optimally provide the operating pressures and flow rates for propagating the expansion cone 375. The pump 325 is preferably adapted to pressurize an interior portion 385 of the expandable tubular member 370 to operating pressures ranging from about 0 to 12,000 psi.

The second fluid conduit 330 is fluidicly coupled to the outlet of the pump 325 and the interior portion 385 of the expandable tubular member 370. The second fluid conduit 330 is further preferably contained within the housing 315. The second fluid conduit 330 is preferably adapted to convey fluidic materials such as, for example, drilling muds, water, and lubricants at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 500 gallons/minute in order to optimally propagate the expansion cone 375.

The third fluid conduit 335 is fluidicly coupled to the exterior region above the housing 315 and the interior portion 385 of the expandable tubular member 370. The third fluid conduit 335 is further preferably contained within the housing 315. The third fluid conduit 330 is preferably adapted to convey fluidic materials such as, for example, drilling muds, water, and lubricants at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 500 gallons/minute in order to optimally propagate the expansion cone 375.

The second support member 340 is coupled to the housing 315 and the third support member 350. The second support member 340 is further preferably movably and sealingly coupled to the expansion cone 375. The second support member 340 preferably has a substantially annular cross section in order to provide one or more conduits for conveying fluidic materials. The second support member 340 is centrally positioned within the expandable tubular member 370.

The fourth fluid conduit 345 is fluidicly coupled to the third fluid conduit 335 and the fifth fluid conduit 355. The fourth fluid conduit 345 is further preferably contained within the second support member 340. The fourth fluid conduit 345 is preferably adapted to convey fluidic materials such as, for example, drilling muds, water, and lubricants at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 500 gallons/minute in order to optimally propagate the expansion cone 375.

The third support member 350 is coupled to the second support member 340. The third support member 350 is further preferably adapted to support the expansion cone 375. The third support member 350 preferably has a substantially annular cross section in order to provide one or more conduits for conveying fluidic materials.

The fifth fluid conduit 355 is fluidicly coupled to the fourth fluid conduit 345 and a portion 390 of the expandable tubular member 375 below the expansion cone 375. The fifth fluid conduit 355 is further preferably contained within the third support member 350. The fifth fluid conduit 355 is preferably adapted to convey fluidic materials such as, for example, drilling muds, water, and lubricants at

The solid lubricants are applied directly to the expandable tubulars as coatings. The coating of the solid lubricant preferably includes a binder to help hold or fix the solid lubricant to the expandable tubular. The binders preferably include curable resins such as, for example, epoxies, acrylic, urea-formaldehyde, melamine formaldehyde, furan based resins, acetone formaldehyde, phenolic, alkyd resins, silicone modified alkyd resins, etc. The binder is preferably selected to withstand the expected temperature range, pH, salinity and fluid types during the installation and radial expansion operations. Polymeric materials are preferably used to bind the solid lubricants to the expandable tubular such as, for example, "self-adhesive" polymers such as those copolymers or terpolymers based upon vinyl acetate, vinyl chloride, maleic annhydride/maleic acid, and ethylene-acrylic acid copolymers, ethylene-methacrylic acid copolymers and ethylene-vinyl acetate copolymers. The solid lubricants are applied as suspensions of fine particles in a carrier solvent without the presence/use of a chemical binder.

The solid lubricant coating and the liquid lubricant additive (added to the fluid in contact with the internal surface of the expandable tubular member during the radial expansion process) interact during the radial expansion process to improve the overall lubrication. For phosphate solid lubricant coatings, manganese phosphate is preferred over zinc or iron phosphate because it more effectively attracts and retains liquid lubricant additives such as oils, esters, amides, etc.

Solid lubricant coatings use binders that provide low friction that is enhanced under extreme pressure conditions by the presence of the solid lubricant. Solid lubricant coatings includes one or more of the following: graphite, molybdenum disulfide, silicone polymers and polytetrafluoroethylene (PTFE). Blends of these materials are used since each material has lubrication characteristics that optimally work at different stages in the radial expansion process. A solid, dry film lubricant coating for the internal surface of the expandable tubular includes: (1) 1 to 90 percent solids by volume; (2) more preferably, 5 to 70 percent solids by volume; and (3) most preferably, 15 to 50 percent solids by volume. The solid lubricants include: (1) 5 to 80 percent graphite; (2) 5 to 80 percent molybdenum disulfide; (3) 1 to 40 percent PTFE; and (4) 1 to 40 percent silicone polymers.

The liquid lubricant additives include one or more of the following: (1) esters including: (a) organic acid esters (preferably fatty acid esters) such as, for example, trimethylol propane, isopropyl, penterithritol, n-butyl, etc.; (b) glycerol tri(acetoxy stearate) and N,N' ethylene bis 12 hydroxystearate and octyl hydroxystearate; (c)

phosphate and phosphite such as, for example, butylated triphenyl phosphate and isodiphenyl phosphate; (2) sulfurized natural and synthetic oils; (3) alkanolamides such as, for example, coco diethanolamide; (4) amines and amine salts; (5) olefins and polyolefins; (6) C-8 to C-18 linear alcohols and derivatives containing or consisting of esters, amines, carboxylates, etc.; (7) overbased sulfonates such as, for example, calcium sulfonate, sodium sulfonate, magnesium sulfonate; (8) polyethylene glycols; (9) silicones and siloxanes such as, for example, dimethylpolysiloxanes and fluorosilicone derivatives; (10) dinonyl phenols; and (11) ethylene oxide/propylene oxide block copolymers.

stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 3065 may be coupled to the lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example, epoxy, cement, water, drilling mud, or lubricants. The load mandrel 3065 is removably coupled to the lower sealing head 3055 by a standard threaded connection.

The load mandrel 3065 preferably includes a fluid passage 3105 that is adapted to convey fluidic materials from the fluid passage 3100 to the region outside of the apparatus 3000. The fluid passage 3105 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 3070 is coupled to the second outer sealing mandrel 3060. The expansion cone 3070 is also movably coupled to the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The reciprocation of the expansion cone 3070 causes the casing 3075 to expand in the radial direction.

The expansion cone 3070 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. The outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide an expansion cone 3070 for expanding typical casings. The axial length of the expansion cone 3070 may range, for example, from about 2 to 8 times the maximum outer diameter of the expansion cone 3070. The axial length of the expansion cone 3070 ranges from about 3 to 5 times the maximum outer diameter of the expansion cone 3070 in order to optimally provide stabilization and centralization of the expansion cone 3070 during the expansion process. The maximum outside diameter of the expansion cone 3070 is between about 95 to 99 % of the inside diameter of the existing wellbore that the casing 3075 will be joined

expandable connectors, or expandable solid connectors. The solid casing 3335 is coupled to the casing 3310 by using expandable solid connectors. The solid casing 3335 may comprise a plurality of such solid casings 3335.

The solid casing 3335 is preferably coupled to one more of the slotted casings 3345. The solid casing 3335 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or slotted and expandable connectors. The solid casing 3335 is coupled to the slotted casing 3345 by expandable solid connectors.

The casing 3335 includes one more valve members 3360 for controlling the flow of fluids and other materials within the interior region of the casing 3335. During the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The casing 3335 is placed into the wellbore 3305 by expanding the casing 3335 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The casing 3335 may be expanded in the radial direction using any number of conventional commercially available methods. The casing 3335 is expanded in the radial direction using one or more of the processes and apparatus described within the present disclosure.

The seals 3340 prevent the passage of fluids and other materials within the annular region 3365 between the solid casings 3335 and 3350 and the wellbore 3305. The seals 3340 may comprise any number of conventional commercially available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. The seals 3340 comprise Stratalok epoxy material available from Halliburton Energy Services.

The slotted casing 3345 permits fluids and other materials to pass into and out of the interior of the slotted casing 3345 from and to the annular region 3365. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The slotted casing 3345 may comprise any number of

conventional commercially available sections of slotted tubular casing. The slotted casing 3345 comprises expandable slotted tubular casing available from Petroline in Aberdeen, Scotland. The slotted casing 145 comprises expandable slotted sandscreen tubular casing available from Petroline in Aberdeen, Scotland.

The slotted casing 3345 is preferably coupled to one or more solid casing 3335. The slotted casing 3345 may be coupled to the solid casing 3335 using any number of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. The slotted casing 3345 is coupled to the solid casing 3335 by expandable solid connectors.

The slotted casing 3345 is preferably coupled to one or more intermediate solid casings 3350. The slotted casing 3345 may be coupled to the intermediate solid casing 3350 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. The slotted casing 3345 is coupled to the intermediate solid casing 3350 by expandable solid connectors.

The last section of slotted casing 3345 is preferably coupled to the shoe 3355. The last slotted casing 3345 may be coupled to the shoe 3355 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. The last slotted casing 3345 is coupled to the shoe 3355 by an expandable solid connector.

The shoe 3355 is coupled directly to the last one of the intermediate solid casings 3350.

The slotted casings 3345 are positioned within the wellbore 3305 by expanding the slotted casings 3345 in a radial direction into intimate contact with the interior walls of the wellbore 3305. The slotted casings 3345 may be expanded in a radial direction using any number of conventional commercially available processes. The slotted casings 3345 are expanded in the radial direction using one or more of the processes and apparatus disclosed in the present disclosure with reference to Figures 14a-20.

The intermediate solid casing 3350 permits fluids and other materials to pass between adjacent slotted casings 3345. The intermediate solid casing 3350 may

comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. The intermediate solid casing 3350 comprises oilfield tubulars available from foreign and domestic steel mills.

The intermediate solid casing 3350 is preferably coupled to one or more sections of the slotted casing 3345. The intermediate solid casing 3350 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or solid or slotted expandable connectors. The intermediate solid casing 3350 is coupled to the slotted casing 3345 by expandable solid connectors. The intermediate solid casing 3350 may comprise a plurality of such intermediate solid casing 3350.

Each intermediate solid casing 3350 includes one more valve members 3370 for controlling the flow of fluids and other materials within the interior region of the intermediate casing 3350. As will be recognized by persons having ordinary skill in the art and the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The intermediate casing 3350 is placed into the wellbore 3305 by expanding the intermediate casing 3350 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The intermediate casing 3350 may be expanded in the radial direction using any number of conventional commercially available methods.

One or more of the intermediate solid casings 3350 may be omitted. One or more of the slotted casings 3345 are provided with one or more seals 3340.

The shoe 3355 provides a support member for the apparatus 3330. In this manner, various production and exploration tools may be supported by the show 3350. The shoe 3350 may comprise any number of conventional commercially available shoes suitable for use in a wellbore such as, for example, cement filled shoe, or an aluminum or composite shoe. The shoe 3350 comprises an aluminum

shoe available from Halliburton. The shoe 3355 is selected to provide sufficient strength in compression and tension to permit the use of high capacity production and exploration tools.

The apparatus 3330 includes a plurality of solid casings 3335, a plurality of seals 3340, a plurality of slotted casings 3345, a plurality of intermediate solid casings 3350, and a shoe 3355. More generally, the apparatus 3330 may comprise one or more solid casings 3335, each with one or more valve members 3360, n slotted casings 3345, n-1 intermediate solid casings 3350, each with one or more valve members 3370, and a shoe 3355.

During operation of the apparatus 3330, oil and gas may be controllably produced from the targeted oil sand zone 3325 using the slotted casings 3345. The oil and gas may then be transported to a surface location using the solid casing 3335. The use of intermediate solid casings 3350 with valve members 3370 permits isolated sections of the zone 3325 to be selectively isolated for production. The seals 3340 permit the zone 3325 to be fluidicly isolated from the zone 3320. The seals 3340 further permits isolated sections of the zone 3325 to be fluidicly isolated from each other. In this manner, the apparatus 3330 permits unwanted and/or non-productive subterranean zones to be fluidicly isolated.

As will be recognized by persons having ordinary skill in the art and also having the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

Referring to Figures 22a, 22b, 22c and 22d, an apparatus 3500 for forming a wellbore casing while drilling a wellbore will now be described. The apparatus 3500 includes a support member 3505, a mandrel 3510, a mandrel launcher 3515, a shoe 3520, a tubular member 3525, a mud motor 3530, a drill bit 3535, a first fluid passage 3540, a second fluid passage 3545, a pressure chamber 3550, a third fluid passage 3555, a cup seal 3560, a body of lubricant 3565, seals 3570, and a releasable coupling 3600.

The support member 3505 is coupled to the mandrel 3510. The support member 3505 preferably comprises an annular member having sufficient strength to carry and support the apparatus 3500 within the wellbore 3575. The support member 3505 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 3500.

The support member 3505 may comprise one or more sections of conventional commercially available tubular materials such as, for example, oilfield country tubular goods, low alloy steel, stainless steel or carbon steel. The support member 3505 comprises coiled tubing or drillpipe in order to optimally permit the placement of the apparatus 3500 within a non-vertical wellbore.

The support member 3505 includes a first fluid passage 3540 for conveying fluidic materials from a surface location to the fluid passage 3545. The first fluid passage 3540 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 10,000 psi and 0 to 3,000 gallons/minute.

The mandrel 3510 is coupled to and supported by the support member 3505. The mandrel 3510 is also coupled to and supports the mandrel launcher 3515 and tubular member 3525. The mandrel 3510 is preferably adapted to controllably expand in a radial direction. The mandrel 3510 may comprise any number of conventional commercially available mandrels modified in accordance with the teachings of the present disclosure. The mandrel 3510 comprises a hydraulic expansion tool as disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The mandrel 3510 includes one or more conical sections for expanding the tubular member 3525 in the radial direction. The outer surfaces of the conical sections of the mandrel 3510 have a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally radially expand the tubular member 3525.

The mandrel 3510 includes a second fluid passage 3545 fluidicly coupled to the first fluid passage 3540 and the pressure chamber 3550 for conveying fluidic materials from the first fluid passage 3540 to the pressure chamber 3550. The

second fluid passage 3545 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 3,500 gallons/minute in order to optimally provide operating pressure for efficient operation.

The mandrel launcher 3515 is coupled to the tubular member 3525, the mandrel 3510, and the shoe 3520. The mandrel launcher 3515 preferably comprises a tapered annular member that mates with at a portion of at least one of the conical portions of the outer surface of the mandrel 3510. The wall thickness of the mandrel launcher is less than the wall thickness of the tubular member 3525 in order to facilitate the initiation of the radial expansion process and facilitate the placement of the apparatus in openings having tight clearances. The wall thickness of the mandrel launcher 3515 ranges from about 50 to 100 % of the wall thickness of the tubular member 3525 immediately adjacent to the mandrel launcher 3515 in order to optimally facilitate the radial expansion process and facilitate the insertion of the apparatus 3500 into wellbore casings and other areas with tight clearances.

The mandrel launcher 3515 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel or stainless steel. The mandrel launcher 3515 is fabricated from oilfield country tubular goods of higher strength by lower wall thickness than the tubular member 3525 in order to optimally provide a smaller container having approximately the same burst strength as the tubular member 3525.

The shoe 3520 is coupled to the mandrel launcher 3515 and the releasable coupling 3600. The shoe 3520 preferably comprises a substantially annular member. The shoe 3520 or the releasable coupling 3600 include a third fluid passage 3555 fluidicly coupled to the pressure chamber 3550 and the mud motor 3530.

The shoe 3520 may comprise any number of conventional commercially available shoes such as, for example, cement filled, aluminum or composite modified in accordance with the teachings of the present disclosure. The shoe 3520 comprises a high strength shoe having a burst strength approximately equal to the burst strength of the tubular member 3525 and mandrel launcher 3515. The shoe

3520 is preferably coupled to the mud motor 3520 by a releasable coupling 3600 in order to optimally provide for removal of the mud motor 3530 and drill nit 3535 upon the completion of a drilling and casing operation.

The shoe 3520 includes a releasable latch mechanism 3600 for retrieving and removing the mud motor 3530 and drill bit 3535 upon the completion of the drilling and casing formation operations. The shoe 3520 further includes an anti-rotation device for maintaining the shoe 3520 in a substantially stationary rotational position during operation of the apparatus 3500. The releasable latch mechanism 3600 is releasably coupled to the shoe 3520.

The tubular member 3525 is supported by and coupled to the mandrel 3510. The tubular member 3525 is expanded in the radial direction and extruded off of the mandrel 3510. The tubular member 3525 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, automotive grade steel, or plastic tubing/casing. The tubular member 3525 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 3525 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. The inner and outer diameters of the tubular member 3525 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 3525 preferably comprises an annular member with solid walls.

The upper end portion 3580 of the tubular member 3525 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 3510 when the mandrel 3510 completes the extrusion of tubular member 3525. For typical tubular member 3525 materials, the length of the tubular member 3525 is preferably limited to between about 40 to 20,000 feet in length. The tubular member 3525 may comprise a single tubular member or, alternatively, a plurality of tubular members coupled to one another.

The mud motor 3530 is coupled to the shoe 3520 and the drill bit 3535. The mud motor 3530 is also fluidicly coupled to the fluid passage 3555. The mud motor

3530 is driven by fluidic materials such as, for example, drilling mud, water, cement, epoxy, lubricants or slag mix conveyed from the fluid passage 3555 to the mud motor 3530. In this manner, the mud motor 3530 drives the drill bit 3535. The operating pressures and flow rates for operating mud motor 3530 may range, for example, from about 0 to 12,000 psi and 0 to 10,000 gallons/minute. The operating pressures and flow rates for operating mud motor 3530 range from about 0 to 5,000 psi and 40 to 3,000 gallons/minute.

The mud motor 3530 may comprise any number of conventional commercially available mud motors, modified in accordance with the teachings of the present disclosure. The size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the drilling and casing operations.

The drill bit 3535 is coupled to the mud motor 3530. The drill bit 3535 is preferably adapted to be powered by the mud motor 3530. In this manner, the drill bit 3535 drills out new sections of the wellbore 3575.

The drill bit 3535 may comprise any number of conventional commercially available drill bits, modified in accordance with the teachings of the present disclosure. The size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the drilling and casing operations. The drill bit 3535 comprises an eccentric drill bit, a bi-centered drill bit, or a small diameter drill bit with an hydraulically actuated under reamer.

The first fluid passage 3540 permits fluidic materials to be transported to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555, and the mud motor 3530. The first fluid passage 3540 is coupled to and positioned within the support member 3505. The first fluid passage 3540 preferably extends from a position adjacent to the surface to the second fluid passage 3545 within the mandrel 3510. The first fluid passage 3540 is preferably positioned along a centerline of the apparatus 3500.

The second fluid passage 3545 permits fluidic materials to be conveyed from the first fluid passage 3540 to the pressure chamber 3550, the third fluid passage 3555, and the mud motor 3530. The second fluid passage 3545 is coupled to and positioned within the mandrel 3510. The second fluid passage 3545 preferably extends from a position adjacent to the first fluid passage 3540 to the bottom of the mandrel 3510. The second fluid passage 3545 is preferably positioned substantially along the centerline of the apparatus 3500.

The pressure chamber 3550 permits fluidic materials to be conveyed from the second fluid passage 3545 to the third fluid passage 3555, and the mud motor 3530. The pressure chamber is preferably defined by the region below the mandrel 3510 and within the tubular member 3525, mandrel launcher 3515, shoe 3520, and releasable coupling 3600. During operation of the apparatus 3500, pressurization of the pressure chamber 3550 preferably causes the tubular member 3525 to be extruded off of the mandrel 3510.

The third fluid passage 3555 permits fluidic materials to be conveyed from the pressure chamber 3550 to the mud motor 3530. The third fluid passage 3555 may be coupled to and positioned within the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 preferably extends from a position adjacent to the pressure chamber 3550 to the bottom of the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 is preferably positioned substantially along the centerline of the apparatus 3500.

The fluid passages 3540, 3545, and 3555 are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally operational efficiency.

The cup seal 3560 is coupled to and supported by the outer surface of the support member 3505. The cup seal 3560 prevents foreign materials from entering the interior region of the tubular member 3525. The cup seal 3560 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. The cup seal 3560 comprises a SIP cup, available from Halliburton

Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant. The apparatus 3500 includes a plurality of such cup seals in order to optimally prevent the entry of foreign material into the interior region of the tubular member 3525 in the vicinity of the mandrel 3510.

A quantity of lubricant 3565 is provided in the annular region above the mandrel 3510 within the interior of the tubular member 3525. In this manner, the extrusion of the tubular member 3525 off of the mandrel 3510 is facilitated. The lubricant 3565 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). The lubricant 3565 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

The seals 3570 are coupled to and supported by the end portion 3580 of the tubular member 3525. The seals 3570 are further positioned on an outer surface of the end portion 3580 of the tubular member 3525. The seals 3570 permit the overlapping joint between the lower end portion 3585 of a preexisting section of casing 3590 and the end portion 3580 of the tubular member 3525 to be fluidicly sealed. The seals 3570 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. The seals 3570 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 3580 of the tubular member 3525 and the end 3585 of the pre-existing casing 3590.

The seals 3570 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 3525 from the pre-existing casing 3590. The frictional force optimally provided by the seals 3570 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 3525.

The releasable coupling 3600 is preferably releasably coupled to the bottom of the shoe 3520. The releasable coupling 3600 includes fluidic seals for sealing the interface between the releasable coupling 3600 and the shoe 3520. In this manner,

the pressure chamber 3550 may be pressurized. The releasable coupling 3600 may comprise any number of conventional commercially available releasable couplings suitable for drilling operations modified in accordance with the teachings of the present disclosure.

As illustrated in Figure 22A, during operation of the apparatus 3500, the apparatus 3500 is preferably initially positioned within a preexisting section of a wellbore 3575 including a preexisting section of wellbore casing 3590. The upper end portion 3580 of the tubular member 3525 is positioned in an overlapping relationship with the lower end 3585 of the preexisting section of casing 3590. The apparatus 3500 is initially positioned in the wellbore 3575 with the drill bit 353 in contact with the bottom of the wellbore 3575. During the initial placement of the apparatus 3500 in the wellbore 3575, the tubular member 3525 is preferably supported by the mandrel 3510.

As illustrated in Figure 22B, a fluidic material 3595 is then pumped into the first fluid passage 3540. The fluidic material 3595 is preferably conveyed from the first fluid passage 3540 to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555 and the inlet to the mud motor 3530. The fluidic material 3595 may comprise any number of conventional commercially available fluidic materials such as, for example, drilling mud, water, cement, epoxy or slag mix. The fluidic material 3595 may be pumped into the first fluid passage 3540 at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material 3595 will enter the inlet for the mud motor 3530 and drive the mud motor 3530. The fluidic material 3595 will then exit the mud motor 3530 and enter the annular region surrounding the apparatus 3500 within the wellbore 3575. The mud motor 3530 will in turn drive the drill bit 3535. The operation of the drill bit 3535 will drill out a new section of the wellbore 3575.

In the case where the fluidic material 3595 comprises a hardenable fluidic material, the fluidic material 3595 preferably is permitted to cure and form an outer annular body surrounding the periphery of the expanded tubular member 3525. Alternatively, in the case where the fluidic material 3595 is a non-hardenable fluidic

material, the tubular member 3595 preferably is expanded into intimate contact with the interior walls of the wellbore 3575. In this manner, an outer annular body is not provided in all applications.

As illustrated in Figure 22C, at some point during operation of the mud motor 3530 and drill bit 3535, the pressure drop across the mud motor 3530 will create sufficient back pressure to cause the operating pressure within the pressure chamber 3550 to elevate to the pressure necessary to extrude the tubular member 3525 off of the mandrel 3510. The elevation of the operating pressure within the pressure chamber 3550 will then cause the tubular member 3525 to extrude off of the mandrel 3510 as illustrated in Figure 22D. For typical tubular members 3525, the necessary operating pressure may range, for example, from about 1,000 to 9,000 psi. In this manner, a wellbore casing is formed simultaneous with the drilling out of a new section of wellbore.

During the operation of the apparatus 3500, the apparatus 3500 is lowered into the wellbore 3575 until the drill bit 3535 is proximate the bottom of the wellbore 3575. Throughout this process, the tubular member 3525 is preferably supported by the mandrel 3510. The apparatus 3500 is then lowered until the drill bit 3535 is placed in contact with the bottom of the wellbore 3575. At this point, at least a portion of the weight of the tubular member 3525 is supported by the drill bit 3535.

The fluidic material 3595 is then pumped into the first fluid passage 3540, second fluid passage 3545, pressure chamber 3550, third fluid passage 3555, and the inlet of the mud motor 3530. The mud motor 3530 then drives the drill bit 3535 to drill out a new section of the wellbore 3575. Once the differential pressure across the mud motor 3530 exceeds the minimum extrusion pressure for the tubular member 3525, the tubular member 3525 begins to extrude off of the mandrel 3510. As the tubular member 3525 is extruded off of the mandrel 3510, the weight of the extruded portion of the tubular member 3525 is transferred to and supported by the drill bit 3535. The pumping pressure of the fluidic material 3595 is maintained substantially constant throughout this process. At some point during the process of extruding the tubular member 3525 off of the mandrel 3510, a sufficient portion of the weight of the tubular member 3525 is transferred to the drill bit 3535 to stop the

extrusion process due to the opposing force. Continued drilling by the drill bit 3535 eventually transfers a sufficient portion of the weight of the extruded portion of the tubular member 3525 back to the mandrel 3510. At this point, the extrusion of the tubular member 3525 off of the mandrel 3510 continues. In this manner, the support member 3505 never has to be moved and no drillpipe connections have to be made at the surface since the new section of the wellbore casing within the newly drilled section of wellbore is created by the constant downward feeding of the expanded tubular member 3525 off of the mandrel 3510.

Once the new section of wellbore that is lined with the fully expanded tubular member 3525 is completed, the support member 3505 and mandrel 3510 are removed from the wellbore 3575. The drilling assembly including the mud motor 3530 and drill bit 3535 are then preferably removed by lowering a drillstring into the new section of wellbore casing and retrieving the drilling assembly by using the latch 3600. The expanded tubular member 3525 is then cemented using conventional squeeze cementing methods to provide a solid annular sealing member around the periphery of the expanded tubular member 3525.

Alternatively, the apparatus 3500 may be used to repair or form an underground pipeline or form a support member for a structure. The teachings of the apparatus 3500 are combined with the teachings of Figures 1-21. For example, by operably coupling the mud motor 3530 and drill bit 3535 to the pressure chambers used to cause the radial expansion of the tubular members of the embodiments illustrated and described with reference to Figures 1-21, the use of plugs may be eliminated and radial expansion of tubular members can be combined with the drilling out of new sections of wellbore.

Referring now to FIGS. 23A, 23B and 23C, an apparatus 3700 for expanding a tubular member will be described. The apparatus 3700 includes a support member 3705, a packer 3710, a first fluid conduit 3715, an annular fluid passage 3720, fluid inlets 3725, an annular seal 3730, a second fluid conduit 3735, a fluid passage 3740, a mandrel 3745, a mandrel launcher 3750, a tubular member 3755, slips 3760, and seals 3765. The apparatus 3700 is used to radially expand the tubular member 3755. In this manner, the apparatus 3700 may be used to form a wellbore casing, line a

wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. The apparatus 3700 is used to clad at least a portion of the tubular member 3755 onto a preexisting tubular member.

The support member 3705 is preferably coupled to the packer 3710 and the mandrel launcher 3750. The support member 3705 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3705 is preferably selected to fit through a preexisting section of wellbore casing 3770. In this manner, the apparatus 3700 may be positioned within the wellbore casing 3770. The support member 3705 is releasably coupled to the mandrel launcher 3750. In this manner, the support member 3705 may be decoupled from the mandrel launcher 3750 upon the completion of an extrusion operation.

The packer 3710 is coupled to the support member 3705 and the first fluid conduit 3715. The packer 3710 preferably provides a fluid seal between the outside surface of the first fluid conduit 3715 and the inside surface of the support member 3705. In this manner, the packer 3710 preferably seals off and, in combination with the support member 3705, first fluid conduit 3715, second fluid conduit 3735, and mandrel 3745, defines an annular chamber 3775. The packer 3710 may comprise any number of conventional commercially available packers modified in accordance with the teachings of the present disclosure.

The first fluid conduit 3715 is coupled to the packer 3710 and the annular seal 3730. The first fluid conduit 3715 preferably comprises an annular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The first fluid conduit 3715 includes one or more fluid inlets 3725 for conveying fluidic materials from the annular fluid passage 3720 into the chamber 3775.

The annular fluid passage 3720 is defined by and positioned between the interior surface of the first fluid conduit 3715 and the interior surface of the second

fluid conduit 3735. The annular fluid passage 3720 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid inlets 3725 are positioned in an end portion of the first fluid conduit 3715. The fluid inlets 3725 preferably are adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The annular seal 3730 is coupled to the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735 during relative axial motion of the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 may comprise any number of conventional commercially available seals such as, for example, o-rings, polypak seals or metal spring energized seals. The annular seal 3730 comprises a polypak seal available from Parker Seals in order to optimally provide sealing for axial motion.

The second fluid conduit 3735 is coupled to the annular seal 3730 and the mandrel 3745. The second fluid conduit preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, coiled tubing, oilfield country tubular goods, low alloy steel, stainless steel, or low carbon steel. The second fluid conduit 3735 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid passage 3740 is coupled to the second fluid conduit 3735 and the mandrel 3745. The fluid passage 3740 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates

ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The mandrel 3745 is coupled to the second fluid conduit 3735 and the mandrel launcher 3750. The mandrel 3745 preferably comprise an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, carbon steel, tool steel, ceramics, or composite materials. The angle of attack the conic section of the mandrel 3745 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3750 and tubular member 3755 in the radial direction. The surface hardness of the conic section of the mandrel 3745 ranges from about 50 Rockwell C to 70 Rockwell C. The surface hardness of the outer surface of the conic section of the mandrel 3745 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. The mandrel 3745 is expandable in order to further optimally augment the radial expansion process.

The mandrel launcher 3750 is coupled to the support member 3705, the mandrel 3745, and the tubular member 3755. The mandrel launcher 3750 preferably comprise a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. The cross-sectional area of the mandrel launcher 3750 at one end is adapted to mate with the mandrel 3745, and at the other end, the cross-sectional area of the mandrel launcher 3750 is adapted to match the cross-sectional area of the tubular member 3755. The wall thickness of the mandrel launcher 3750 ranges from about 50 to 100 % of the wall thickness of the tubular member 3755 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 3750 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low allow steel, stainless steel, or carbon steel. The mandrel launcher 3750 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 3755 in order to optimally match the burst strength of the tubular member 3755. The mandrel launcher 3750 is removably coupled to the tubular member 3755. In this manner, the mandrel

launcher 3750 may be removed from the wellbore 3780 upon the completion of an extrusion operation.

The tubular member 3755 is coupled to the mandrel launcher, the slips 3760 and the seals 3765. The tubular member 3755 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. The tubular member 3755 is fabricated from oilfield country tubular goods.

The slips 3760 are coupled to the outside surface of the tubular member 3755. The slips 3760 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3755. In this manner, the slips 3760 provide structural support for the expanded tubular member 3755. The slips 3760 may comprise any number of conventional commercially available slips, modified in accordance with the teachings of the present disclosure.

The seals 3765 are coupled to the outside surface of the tubular member 3755. The seals 3765 preferably provide a fluidic seal between the outside surface of the expanded tubular member 3755 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3755. In this manner, the seals 3765 provide a fluidic seal for the expanded tubular member 3755. The seals 3765 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon or epoxy seals modified in accordance with the teachings of the present disclosure. The seals 3765 comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the overlapping joint and optimally provide load carrying capacity to withstand the range of typical tensile and compressive loads.

During operation of the apparatus 3700, the apparatus 3700 is preferably lowered into a wellbore 3780 having a preexisting section of wellbore casing 3770. The apparatus 3700 is positioned with at least a portion of the tubular member 3755 overlapping with a portion of the wellbore casing 3770. In this manner, the radial

expansion of the tubular member 3755 will preferably cause the outside surface of the expanded tubular member 3755 to couple with the inside surface of the wellbore casing 3770. The radial expansion of the tubular member 3755 will also cause the slips 3760 and seals 3765 to engage with the interior surface of the wellbore casing 3770. In this manner, the expanded tubular member 3755 is provided with enhanced structural support by the slips 3760 and an enhanced fluid seal by the seals 3765.

As illustrated in FIG. 23B, after placement of the apparatus 3700 in an overlapping relationship with the wellbore casing 3770, a fluidic material 3785 is preferably pumped into the chamber 3775 using the fluid passage 3720 and the inlet passages 3725. The fluidic material is pumped into the chamber 3775 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The pumped fluidic material 3785 increase the operating pressure within the chamber 3775. The increased operating pressure in the chamber 3775 then causes the mandrel 3745 to extrude the mandrel launcher 3750 and tubular member 3755 off of the face of the mandrel 3745. The extrusion of the mandrel launcher 3750 and tubular member 3755 off of the face of the mandrel 3745 causes the mandrel launcher 3750 and tubular member 3755 to expand in the radial direction. Continued pumping of the fluidic material 3785 preferably causes the entire length of the tubular member 3755 to expand in the radial direction.

The pumping rate and pressure of the fluidic material 3785 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 3700. The apparatus 3700 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process.

The extrusion process causes the mandrel 3745 to move in an axial direction 3785. During the axial movement of the mandrel, The fluid passage 3740 conveys fluidic material 3790 displaced by the moving mandrel 3745 out of the wellbore 3780. In this manner, the operational efficiency and speed of the extrusion process is enhanced.

The extrusion process includes the injection of a hardenable fluidic material into the annular region between the tubular member 3755 and the bore hole 3780. In

this manner, a hardened sealing layer is provided between the expanded tubular member 3755 and the interior walls of the wellbore 3780.

As illustrated in FIG. 23C, upon the completion of the extrusion process, the support member 3705, packer 3710, first fluid conduit 3715, annular seal 3730, second fluid conduit 3735, mandrel 3745, and mandrel launcher 3750 are moved from the wellbore 3780.

The apparatus 3700 is used to repair a preexisting wellbore casing, pipeline, or structural support. Both ends of the tubular member 3755 preferably include slips 3760 and seals 3765.

The apparatus 3700 is used to form a tubular structural support for a building or offshore structure.

Referring now to FIGS. 24A, 24B, 24C, 24D, and 24E, an apparatus 3900 for expanding a tubular member will be described. The apparatus 3900 includes a support member 3905, a mandrel launcher 3910, a mandrel 3915, a first fluid passage 3920, a tubular member 3925, slips 3930, seals 3935, a shoe 3940, and a second fluid passage 3945. The apparatus 3900 is used to radially expand the mandrel launcher 3910 and tubular member 3925. In this manner, the apparatus 3900 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. The apparatus 3900 is used to clad at least a portion of the tubular member 3925 onto a preexisting structural member.

The support member 3905 is preferably coupled to the mandrel launcher 3910. The support member 3905 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3905, the mandrel launcher 3910, the tubular member 3925, and the shoe 3940 are preferably selected to fit through a preexisting section of wellbore casing 3950. In this manner, the apparatus 3900 may be positioned within the wellbore casing 3970. The support member 3905 is releasably coupled to the mandrel launcher 3910. In this manner, the support member 3905 may be

decoupled from the mandrel launcher 3910 upon the completion of an extrusion operation.

The mandrel launcher 3910 is coupled to the support member 3905 and the tubular member 3925. The mandrel launcher 3910 preferably comprise a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. The cross-sectional area of the mandrel launcher 3910 at one end is adapted to mate with the mandrel 3915, and at the other end, the cross-sectional area of the mandrel launcher 3910 is adapted to match the cross-sectional area of the tubular member 3925. The wall thickness of the mandrel launcher 3910 ranges from about 50 to 100 % of the wall thickness of the tubular member 3925 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 3910 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low allow steel, stainless steel, or carbon steel. The mandrel launcher 3910 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 3925 in order to optimally match the burst strength of the tubular member 3925. The mandrel launcher 3910 is removably coupled to the tubular member 3925. In this manner, the mandrel launcher 3910 may be removed from the wellbore 3960 upon the completion of an extrusion operation.

The mandrel 3915 is coupled to the mandrel launcher 3910. The mandrel 3915 preferably comprise an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, tool steel, carbon steel, ceramics, or composite materials. The angle of attack of the conic section of the mandrel 3915 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3910 and the tubular member 3925 in the radial direction. The surface hardness of the conic section of the mandrel 3915 ranges from about 58 to 62 Rockwell C in order to optimally provide high strength and resist wear and galling. The mandrel 3915 is expandable in order to further optimally augment the radial expansion process.

The fluid passage 3920 is positioned within the mandrel 3915. The fluid passage 3920 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The fluid passage 3920 preferably includes an inlet 3965 adapted to receive a plug, or other similar device. In this manner, the interior chamber 3970 above the mandrel 3915 may be fluidicly isolated from the interior chamber 3975 below the mandrel 3915.

The tubular member 3925 is coupled to the mandrel launcher 3910, the slips 3930 and the seals 3935. The tubular member 3925 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. The tubular member 3925 is fabricated from oilfield country tubular goods.

The slips 3930 are coupled to the outside surface of the tubular member 3925. The slips 3930 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3925. In this manner, the slips 3930 provide structural support for the expanded tubular member 3925. The slips 3930 may comprise any number of conventional commercially available slips, modified in accordance with the teachings of the present disclosure.

The seals 3935 are coupled to the outside surface of the tubular member 3925. The seals 3935 preferably provide a fluidic seal between the outside surface of the expanded tubular member 3925 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3925. In this manner, the seals 3935 provide a fluidic seal for the expanded tubular member 3925. The seals 3935 may comprise any number of conventional commercially available seals such as, for example, lead, rubber or epoxy. The seals 3935 comprise Stratalok epoxy material available from Halliburton Energy Services in order to optimally provide structural support for the typical tensile and compressive loads.

The shoe 3940 is coupled to the tubular member 3925. The shoe 3940 preferably comprises a substantially tubular member having a fluid passage 3945 for conveying fluidic materials from the chamber 3975 to the annular region 3970 outside of the apparatus 3900. The shoe 3940 may comprise any number of conventional commercially available shoes modified in accordance with the teachings of the present disclosure.

During operation of the apparatus 3900, the apparatus 3900 is preferably lowered into a wellbore 3960 having a preexisting section of wellbore casing 3975. The apparatus 3900 is positioned with at least a portion of the tubular member 3925 overlapping with a portion of the wellbore casing 3975. In this manner, the radial expansion of the tubular member 3925 will preferably cause the outside surface of the expanded tubular member 3925 to couple with the inside surface of the wellbore casing 3975. The radial expansion of the tubular member 3925 will also cause the slips 3930 and seals 3935 to engage with the interior surface of the wellbore casing 3975. In this manner, the expanded tubular member 3925 is provided with enhanced structural support by the slips 3930 and an enhanced fluid seal by the seals 3935.

As illustrated in FIG. 24B, after placement of the apparatus 3900 in an overlapping relationship with the wellbore casing 3975, a fluidic material 3980 is preferably pumped into the chamber 3970. The fluidic material 3980 then passes through the fluid passage 3920 into the chamber 3975. The fluidic material 3980 then passes out of the chamber 3975, through the fluid passage 3945, and into the annular region 3970. The fluidic material 3980 is pumped into the chamber 3970 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The fluidic material 3980 comprises a hardenable fluidic sealing material in order to form a hardened outer annular member around the expanded tubular member 3925.

As illustrated in FIG. 24C, at some later point in the process, a ball 3985, plug or other similar device, is introduced into the pumped fluidic material 3980. The ball 3985 mates with and seals off the inlet 3965 of the fluid passage 3920. In this manner, the chamber 3970 is fluidicly isolated from the chamber 3975.

As illustrated in FIG. 24D, after placement of the ball 3985 in the inlet 3965 of the fluid passage 3920, a fluidic material 3990 is pumped into the chamber 3970. The fluidic material is preferably pumped into the chamber 3970 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to provide optimal operating efficiency. The fluidic material 3990 may comprise any number of conventional commercially available materials such as, for example, water, drilling mud, cement, epoxy, or slag mix. The fluidic material 3990 comprises a non-hardenable fluidic material in order to maximize operational efficiency.

Continued pumping of the fluidic material 3990 increases fluidic material 3980 increases the operating pressure within the chamber 3970. The increased operating pressure in the chamber 3970 then causes the mandrel 3915 to extrude the mandrel launcher 3910 and tubular member 3925 off of the conical face of the mandrel 3915. The extrusion of the mandrel launcher 3910 and tubular member 3925 off of the conical face of the mandrel 3915 causes the mandrel launcher 3910 and tubular member 3925 to expand in the radial direction. Continued pumping of the fluidic material 3990 preferably causes the entire length of the tubular member 3925 to expand in the radial direction.

The pumping rate and pressure of the fluidic material 3990 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 3900. The apparatus 3900 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process. The extrusion process causes the mandrel 3915 to move in an axial direction 3995.

As illustrated in FIG. 24E, upon the completion of the extrusion process, the support member 3905, packer 3910, first fluid conduit 3915, annular seal 3930, second fluid conduit 3935, mandrel 3945, and mandrel launcher 3950 are removed from the wellbore 3980. The resulting new section of wellbore casing includes the preexisting wellbore casing 3975, the expanded tubular member 3925, the slips 3930, the seals 3935, the shoe 3940, and an outer annular layer 4000 of hardened fluidic material.

The apparatus 3900 is used to repair a preexisting wellbore casing or pipeline. Both ends of the tubular member 3955 preferably include slips 3960 and seals 3965.

The apparatus 3900 is used to form a tubular structural support for a building or offshore structure.

Referring to FIGS. 25 and 26, the optimal relationship between the angle of attack of an expansion mandrel and the minimally required propagation pressure during the expansion of a tubular member will now be described. As illustrated in FIG. 25, during the radial expansion of a tubular member 4100 by an expansion mandrel 4105, the expansion mandrel 4105 is displaced in the axial direction. The angle of attack " of the conical surface 4110 of the expansion mandrel 4105 directly affects the required propagation pressure P_{PR} necessary to radially expand the tubular member 4100. Referring to FIG. 26, for typical grades of materials and typical geometries, the propagation pressure P_{PR} is minimized for an angle of attack of approximately 25 degrees. Furthermore, the optimal range of the angle of attack " ranges from about 10 to 30 degrees in order to minimize the range of required minimum propagation pressure P_{PR}.

Referring to FIG. 27, an expandable threaded connection 4300 will now be described. The expandable threaded connection 4300 preferably includes a first tubular member 4305, a second tubular member 4310, a threaded connection 4315, an O-ring groove 4320, and an O-ring 4325.

The first tubular member 4305 includes an inside wall 4330 and an outside wall 4335. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4310 includes an inside wall 4340 and an outside wall 4345. The second tubular member 4310 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4305 and 4310, may comprise any number of conventional commercially available members. The inside and outside diameters of the first and second tubular members, 4305 and 4310, are substantially equal. In this manner, the burst strength of the tubular members, 4305 and 4310, are

substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4315 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4315 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4305 to the second tubular member 4310 is optimized.

The O-ring groove 4320 is preferably provided in the threaded portion of the interior wall 4340 of the second tubular member 4310. The O-ring groove 4320 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4320 is preferably selected to permit the O-ring 4325 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4345 of the second tubular member 4310 during and upon the completion of the radial expansion process is minimized.

The O-ring 4325 is supported by the O-ring groove 4320. The O-ring 4325 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4305 and the second tubular member 4310 throughout and upon the completion of the radial expansion process.

Referring to FIG. 28, an expandable threaded connection 4500 will now be described. The expandable threaded connection 4500 includes a first tubular member 4505, a second tubular member 4510, a threaded connection 4515, an O-ring groove 4520, and an O-ring 4525.

The first tubular member 4505 includes an inside wall 4530 and an outside wall 4535. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4510 includes an inside wall 4540 and an outside wall 4545. The second tubular member 4510 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4505 and 4510, may comprise any number of conventional commercially available members. The inside and outside

diameters of the first and second tubular members, 4505 and 4510, are substantially equal. In this manner, the burst strength of the tubular members, 4505 and 4510, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4515 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4515 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4505 to the second tubular member 4510 is optimized.

The O-ring groove 4520 is preferably provided in the threaded portion of the interior wall 4540 of the second tubular member 4510 immediately adjacent to an end portion of the threaded connection 4515. In this manner, the sealing effect provided by the O-ring 4525 is optimized. The O-ring groove 4520 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4520 is preferably selected to permit the O-ring 4525 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4545 of the second tubular member 4510 during and upon the completion of the radial expansion process is minimized.

The O-ring 4525 is supported by the O-ring groove 4520. The O-ring 4525 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4505 and the second tubular member 4510 throughout and upon the completion of the radial expansion process.

Referring to FIG. 29, an expandable threaded connection 4700 will now be described. The expandable threaded connection 4700 includes a first tubular member 4705, a second tubular member 4710, a threaded connection 4715, an O-ring groove 4720, a first O-ring 4725, and a second O-ring 4730.

The first tubular member 4705 includes an inside wall 4735 and an outside wall 4740. The first tubular member 4705 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4710 includes an inside wall 4745 and an outside wall 4750. The second tubular member

4710 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4705 and 4710, may comprise any number of conventional commercially available members. The inside and outside diameters of the first and second tubular members, 4705 and 4710, are substantially equal. In this manner, the burst strength of the tubular members, 4705 and 4710, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4715 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4715 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4705 to the second tubular member 4710 is optimized.

The O-ring groove 4720 is preferably provided in the threaded portion of the interior wall 4745 of the second tubular member 4710 immediately adjacent to an end portion of the threaded connection 4715. In this manner, the sealing effect provided by the O-rings, 4725 and 4730, is optimized. The O-ring groove 4720 is preferably adapted to receive and support a plurality of O-rings. The volumetric size of the O-ring groove 4720 is preferably selected to permit the O-rings, 4725 and 4730, to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4750 of the second tubular member 4710 during and upon the completion of the radial expansion process is minimized.

The O-rings, 4725 and 4730, are supported by the O-ring groove 4720. The pair of O-rings, 4725 and 4730, optimally ensure that a fluid-tight seal is maintained between the first tubular member 4705 and the second tubular member 4710 throughout and upon the completion of the radial expansion process. In particular, the use of a pair of adjacent O-rings provides redundancy in the seal between the first tubular member 4705 and the second tubular member 4710.

Referring to FIG. 30, an expandable threaded connection 4900 will now be described. The expandable threaded connection 4900 includes a first tubular

member 4905, a second tubular member 4910, a threaded connection 4915, a first O-ring groove 4920, a second O-ring grove 4925, a first O-ring 4930, and a second O-ring 4935.

The first tubular member 4905 includes an inside wall 4940 and an outside wall 4945. The first tubular member 4905 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4910 includes an inside wall 4950 and an outside wall 4955. The second tubular member 4910 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4905 and 4910, may comprise any number of conventional commercially available tubular members. The inside and outside diameters of the first and second tubular members, 4905 and 4910, are substantially equal. In this manner, the burst strength of the tubular members, 4905 and 4910, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4915 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4915 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4905 to the second tubular member 4910 is optimized.

The first O-ring groove 4920 is preferably provided in the threaded portion of the interior wall 4950 of the second tubular member 4910 that is separated from an end portion of the threaded connection 4915. In this manner, the sealing effect provided by the O-rings, 4930 and 4935, is optimized. The first O-ring groove 4920 is preferably adapted to receive and support one more O-rings. The volumetric size of the first O-ring groove 4920 is preferably selected to permit the O-ring 4930 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4955 of the second tubular member 4910 during and upon the completion of the radial expansion process is minimized.

The second O-ring groove 4925 is preferably provided in the threaded portion of the interior wall 4950 of the second tubular member 4910 that is immediately adjacent to an end portion of the threaded connection 4915. In this manner, the sealing effect provided by the O-rings, 4930 and 4935, is optimized. The second O-ring groove 4925 is preferably adapted to receive and support one more O-rings. The volumetric size of the second O-ring groove 4925 is preferably selected to permit the O-ring 4935 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4955 of the second tubular member 4910 during and upon the completion of the radial expansion process is minimized.

The O-rings, 4930 and 4935, are supported by the O-ring grooves, 4920 and 4925. The use of a pair of O-rings, 4930 and 4935, that are axially separated optimally ensures that a fluid-tight seal is maintained between the first tubular member 4905 and the second tubular member 4910 throughout and upon the completion of the radial expansion process. In particular, the use of a pair of O-rings provides redundancy in the seal between the first tubular member 4905 and the second tubular member 4910.

The expandable threaded connections 4300, 4500, 4700, and/or 4900 are used in combination with one or more of the embodiments illustrated in FIGS. 1-24E in order to optimally expand a plurality of tubular members coupled end to end using the expandable threaded connections 4300, 4500, 4700 and/or 4900.

Referring to FIG. 31, the lubrication of the interface between an expansion mandrel and a tubular member during the radial expansion process will now be described. As illustrated in FIG. 31, during the radial expansion process, an expansion cone 5000 radially expands a tubular member 5005 by moving in an axial direction 5010 relative to the tubular member 5005. The interface between the outer surface 5010 of the tapered portion 5015 of the expansion cone 5000 and the inner surface 5020 of the tubular member 5005 includes a leading edge portion 5025 and a trailing edge portion 5030.

During the radial expansion process, the leading edge portion 5025 is preferably lubricated by the presence of lubricating fluids provided ahead of the

expansion cone 5000. However, because the radial clearance between the expansion cone 5000 and the tubular member 5005 in the trailing edge portion 5030 during the radial expansion process is typically extremely small, and the operating contact pressures between the tubular member 5005 and the expansion mandrel 5000 are extremely high, the quantity of lubricating fluid provided to the trailing edge portion 5030 is typically greatly reduced. In typical radial expansion operations, this reduction in lubrication in the trailing edge portion 5030 increases the forces required to radially expand the tubular member 5005.

Referring to FIG. 32, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 32, an expansion cone 5100, having a front end 5100a and a rear end 5100b, includes a tapered portion 5105 having an outer surface 3110, one or more circumferential grooves 5115a and 5115b, and one more internal flow passages 5120a and 5120b.

The circumferential grooves 5115 are fluidicly coupled to the internal flow passages 5120. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5100a of the expansion cone 5100 into the circumferential grooves 5115. Thus, the trailing edge portion of the interface between the expansion cone 5100 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. The lubricating fluids are injected into the internal flow passages 5120 using a fluid conduit that is coupled to the tapered end 5105 of the expansion cone 5100. Alternatively, lubricating fluids are provided for the internal flow passages 5120 using a supply of lubricating fluids provided adjacent to the front 5100a of the expansion cone 5100.

The expansion cone 5100 includes a plurality of circumferential grooves 5115. The cross sectional area of the circumferential grooves 5115 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process. The expansion cone 5100 includes circumferential grooves 5115 concentrated about the axial midpoint of the tapered

portion 5105 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process. The circumferential grooves 5115 are equally spaced along the trailing edge portion of the expansion cone 5100 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process.

The expansion cone 5100 includes a plurality of flow passages 5120 coupled to each of the circumferential grooves 5115. The cross-sectional area of the flow passages 5120 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5100 and a tubular member during the radial expansion process. The cross sectional area of the circumferential grooves 5115 is greater than the cross sectional area of the flow passage 5120 in order to minimize resistance to fluid flow.

Referring to FIG. 33, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 33, an expansion cone 5200, having a front end 5200a and a rear end 5200b, includes a tapered portion 5205 having an outer surface 5210, one or more circumferential grooves 5215a and 5215b, and one or more axial grooves 5220a and 5220b.

The circumferential grooves 5215 are fluidicly coupled to the axial groves 5220. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5200a of the expansion cone 5200 into the circumferential grooves 5215. Thus, the trailing edge portion of the interface between the expansion cone 5200 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. The axial grooves 5220 are provided with lubricating fluid using a supply of lubricating fluid positioned proximate the front end 5200a of the expansion cone 5200. The circumferential grooves 3215 are concentrated about the axial midpoint of the tapered portion 5205 of the expansion cone 5200 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial

expansion process. The circumferential grooves 5215 are equally spaced along the trailing edge portion of the expansion cone 5200 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process.

The expansion cone 5200 includes a plurality of circumferential grooves 5215. The cross sectional area of the circumferential grooves 5215 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process.

The expansion cone 5200 includes a plurality of axial grooves 5220 coupled to each of the circumferential grooves 5215. The cross sectional area of the axial grooves 5220 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5200 and a tubular member during the radial expansion process. The cross sectional area of the circumferential grooves 5215 is greater than the cross sectional area of the axial grooves 5220 in order to minimize resistance to fluid flow. The axial groves 5220 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 34, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 34, an expansion cone 5300, having a front end 5300a and a rear end 5300b, includes a tapered portion 5305 having an outer surface 5310, one or more circumferential grooves 5315a and 5315b, and one or more internal flow passages 5320a and 5320b.

The circumferential grooves 5315 are fluidicly coupled to the internal flow passages 5320. In this manner, during the radial expansion process, lubricating fluids are transmitted from the areas in front of the front 5300a and/or behind the rear 5300b of the expansion cone 5300 into the circumferential grooves 5315. Thus, the trailing edge portion of the interface between the expansion cone 5300 and a tubular member is provided with an increased supply of lubricant, thereby reducing

the amount of force required to radially expand the tubular member. Furthermore, the lubricating fluids also preferably pass to the area in front of the expansion cone. In this manner, the area adjacent to the front 5300a of the expansion cone 5300 is cleaned of foreign materials. The lubricating fluids are injected into the internal flow passages 5320 by pressurizing the area behind the rear 5300b of the expansion cone 5300 during the radial expansion process.

The expansion cone 5300 includes a plurality of circumferential grooves 5315. The cross sectional area of the circumferential grooves 5315 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 respectively, in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. The expansion cone 5300 includes circumferential grooves 5315 that are concentrated about the axial midpoint of the tapered portion 5305 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. The circumferential grooves 5315 are equally spaced along the trailing edge portion of the expansion cone 5300 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process.

The expansion cone 5300 includes a plurality of flow passages 5320 coupled to each of the circumferential grooves 5315. The flow passages 5320 fluidicly couple the front end 5300a and the rear end 5300b of the expansion cone 5300. The cross-sectional area of the flow passages 5320 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5300 and a tubular member during the radial expansion process. The cross sectional area of the circumferential grooves 5315 is greater than the cross-sectional area of the flow passages 5320 in order to minimize resistance to fluid flow.

Referring to FIG. 35, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 35, an expansion cone 5400, having a front end 5400a and a rear end 5400b, includes a tapered portion 5405 having an outer

surface 5410, one or more circumferential grooves 5415a and 5415b, and one or more axial grooves 5420a and 5420b.

The circumferential grooves 5415 are fluidicly coupled to the axial grooves 5420. In this manner, during the radial expansion process, lubricating fluids are transmitted from the areas in front of the front 5400a and/or behind the rear 5400b of the expansion cone 5400 into the circumferential grooves 5415. Thus, the trailing edge portion of the interface between the expansion cone 5400 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. Furthermore, pressurized lubricating fluids pass from the fluid passages 5420 to the area in front of the front 5400a of the expansion cone 5400. In this manner, the area adjacent to the front 5400a of the expansion cone 5400 is cleaned of foreign materials. The lubricating fluids are injected into the internal flow passages 5420 by pressurizing the area behind the rear 5400b expansion cone 5400 during the radial expansion process.

The expansion cone 5400 includes a plurality of circumferential grooves 5415. The cross sectional area of the circumferential grooves 5415 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. The expansion cone 5400 includes circumferential grooves 5415 that are concentrated about the axial midpoint of the tapered portion 5405 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. The circumferential grooves 5415 are equally spaced along the trailing edge portion of the expansion cone 5400 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process.

The expansion cone 5400 includes a plurality of axial grooves 5420 coupled to each of the circumferential grooves 5415. The axial grooves 5420 fluidicly couple the front end and the rear end of the expansion cone 5400. The cross sectional area of the axial grooves 5420 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2, respectively, in

order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5400 and a tubular member during the radial expansion process. The cross sectional area of the circumferential grooves 5415 is greater than the cross sectional area of the axial grooves 5420 in order to minimize resistance to fluid flow. The axial grooves 5420 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 36, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 36, an expansion cone 5500, having a front end 5500a and a rear end 5500b, includes a tapered portion 5505 having an outer surface 5510, one or more circumferential grooves 5515a and 5515b, and one or more axial grooves 5520a and 5520b.

The circumferential grooves 5515 are fluidicly coupled to the axial grooves 5520. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5500a of the expansion cone 5500 into the circumferential grooves 5515. Thus, the trailing edge portion of the interface between the expansion cone 5500 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. The lubricating fluids are injected into the axial grooves 5520 using a fluid conduit that is coupled to the tapered end 3205 of the expansion cone 3200.

The expansion cone 5500 includes a plurality of circumferential grooves 5515. The cross sectional area of the circumferential grooves 5515 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process. The expansion cone 5500 includes circumferential grooves 5515 that are concentrated about the axial midpoint of the tapered portion 5505 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process. The circumferential grooves 5515 are equally

spaced along the trailing edge portion of the expansion cone 5500 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process.

The expansion cone 5500 includes a plurality of axial grooves 5520 coupled to each of the circumferential grooves 5515. The axial grooves 5520 intersect each of the circumferential groves 5515 at an acute angle. The cross sectional area of the axial grooves 5520 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5500 and a tubular member during the radial expansion process. The cross sectional area of the circumferential grooves 5515 is greater than the cross sectional area of the axial grooves 5520. The axial grooves 5520 are spaced apart in the circumferential direction by at least about 3 inches in order to optimally provide lubrication during the radial expansion process. The axial grooves 5520 intersect the longitudinal axis of the expansion cone 5500 at a larger angle than the angle of attack of the tapered portion 5505 in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 37, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 37, an expansion cone 5600, having a front end 5600a and a rear end 5600b, includes a tapered portion 5605 having an outer surface 5610, a spiral circumferential groove 5615, and one or more internal flow passages 5620.

The circumferential groove 5615 is fluidicly coupled to the internal flow passage 5620. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5600a of the expansion cone 5600 into the circumferential groove 5615. Thus, the trailing edge portion of the interface between the expansion cone 5600 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. The lubricating fluids are injected into the internal flow passage 5620 using a fluid conduit that is coupled to the tapered end 5605 of the expansion cone 5600.

The expansion cone 5600 includes a plurality of spiral circumferential grooves 5615. The cross sectional area of the circumferential groove 5615 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process. The expansion cone 5600 includes circumferential grooves 5615 that are concentrated about the axial midpoint of the tapered portion 5605 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process. The circumferential grooves 5615 are equally spaced along the trailing edge portion of the expansion cone 5600 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process.

The expansion cone 5600 includes a plurality of flow passages 5620 coupled to each of the circumferential grooves 5615. The cross-sectional area of the flow passages 5620 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5600 and a tubular member during the radial expansion process. The cross sectional area of the circumferential groove 5615 is greater than the cross sectional area of the flow passage 5620 in order to minimize resistance to fluid flow.

Referring to FIG. 38, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 38, an expansion cone 5700, having a front end 5700a and a rear end 5700b, includes a tapered portion 5705 having an outer surface 5710, a spiral circumferential groove 5715, and one or more axial grooves 5720a, 5720b and 5720c.

The circumferential groove 5715 is fluidicly coupled to the axial grooves 5720. In this manner, during the radial expansion process, lubricating fluids are transmitted from the area ahead of the front 5700a of the expansion cone 5700 into the circumferential groove 5715. Thus, the trailing edge portion of the interface between the expansion cone 5700 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to

radially expand the tubular member. The lubricating fluids are injected into the axial grooves 5720 using a fluid conduit that is coupled to the tapered end 5705 of the expansion cone 5700.

The expansion cone 5700 includes a plurality of spiral circumferential grooves 5715. The cross sectional area of the circumferential grooves 5715 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process. The expansion cone 5700 includes circumferential grooves 5715 concentrated about the axial midpoint of the tapered portion 5705 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process. The circumferential grooves 5715 are equally spaced along the trailing edge portion of the expansion cone 5700 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process.

The expansion cone 5700 includes a plurality of axial grooves 5720 coupled to each of the circumferential grooves 5715. The cross sectional area of the axial grooves 5720 range from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5700 and a tubular member during the radial expansion process. The axial grooves 5720 intersect the circumferential grooves 5715 in a perpendicular manner. The cross sectional area of the circumferential groove 5715 is greater than the cross sectional area of the axial grooves 5720 in order to minimize resistance to fluid flow. The circumferential spacing of the axial grooves is greater than about 3 inches in order to optimally provide lubrication during the radial expansion process. The axial grooves 5720 intersect the longitudinal axis of the expansion cone at an angle greater than the angle of attack of the tapered portion 5705 in order to optimally provide lubrication during the radial expansion process.

Referring to FIG. 39, a system for lubricating the interface between an expansion cone and a tubular member during the expansion process will now be described. As illustrated in FIG. 39, an expansion cone 5800, having a front end

5800a and a rear end 5800b, includes a tapered portion 5805 having an outer surface 5810, a circumferential groove 5815, a first axial groove 5820, and one or more second axial grooves 5825a, 5825b, 5825c and 5825d.

The circumferential groove 5815 is fluidicly coupled to the axial grooves 5820 and 5825. In this manner, during the radial expansion process, lubricating fluids are preferably transmitted from the area behind the back 5800b of the expansion cone 5800 into the circumferential groove 5815. Thus, the trailing edge portion of the interface between the expansion cone 5800 and a tubular member is provided with an increased supply of lubricant, thereby reducing the amount of force required to radially expand the tubular member. The lubricating fluids are injected into the first axial groove 5820 by pressurizing the region behind the back 5800b of the expansion cone 5800. The lubricant is further transmitted into the second axial grooves 5825 where the lubricant preferably cleans foreign materials from the tapered portion 5805 of the expansion cone 5800.

The expansion cone 5800 includes a plurality of circumferential grooves 5815. The cross sectional area of the circumferential groove 5815 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. The expansion cone 5800 includes circumferential grooves 5815 concentrated about the axial midpoint of the tapered portion 5805 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. The circumferential grooves 5815 are equally spaced along the trailing edge portion of the expansion cone 5800 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process.

The expansion cone 5800 includes a plurality of first axial grooves 5820 coupled to each of the circumferential grooves 5815. The first axial grooves 5820 extend from the back 5800b of the expansion cone 5800 and intersect the circumferential groove 5815. The cross sectional area of the first axial groove 5820 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication

to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. The first axial groove 5820 intersects the circumferential groove 5815 in a perpendicular manner. The cross sectional area of the circumferential groove 5815 is greater than the cross sectional area of the first axial groove 5820 in order to minimize resistance to fluid flow. The circumferential spacing of the first axial grooves 5820 is greater than about 3 inches in order to optimally provide lubrication during the radial expansion process.

The expansion cone 5800 includes a plurality of second axial grooves 5825 coupled to each of the circumferential grooves 5815. The second axial grooves 5825 extend from the front 5800a of the expansion cone 5800 and intersect the circumferential groove 5815. The cross sectional area of the second axial grooves 5825 ranges from about $2X10^{-4}$ in^2 to $5X10^{-2}$ in^2 in order to optimally provide lubrication to the trailing edge portion of the interface between the expansion cone 5800 and a tubular member during the radial expansion process. The second axial grooves 5825 intersect the circumferential groove 5815 in a perpendicular manner. The cross sectional area of the circumferential groove 5815 is greater than the cross sectional area of the second axial grooves 5825 in order to minimize resistance to fluid flow. The circumferential spacing of the second axial grooves 5825 is greater than about 3 inches in order to optimally provide lubrication during the radial expansion process. The second axial grooves 5825 intersect the longitudinal axis of the expansion cone 5800 at an angle greater than the angle of attack of the tapered portion 5805 in order to optimally provide lubrication during the radial expansion process.

Referring to Fig. 40, The first axial groove 5820 includes a first portion 5905 having a first radius of curvature 5910, a second portion 5915 having a second radius of curvature 5920, and a third portion 5925 having a third radius of curvature 5930. The radius of curvatures, 5910, 5920 and 5930 are substantially equal. The radius of curvatures, 5910, 5920 and 5930 are all substantially equal to 0.0625 inches.

Referring to Fig. 41, The circumferential groove 5815 includes a first portion 6005 having a first radius of curvature 6010, a second portion 6015 having a second

radius of curvature 6020, and a third portion 6025 having a third radius of curvature 6030. The radius of curvatures, 6010, 6020 and 6030 are substantially equal. The radius of curvatures, 6010, 6020 and 6030 are all substantially equal to 0.125 inches.

Referring to Fig. 42, The second axial groove 5825 includes a first portion 6105 having a first radius of curvature 6110, a second portion 6115 having a second radius of curvature 6120, and a third portion 6125 having a third radius of curvature 6130. The first radius of curvature 6110 is greater than the third radius of curvature 6130. The first radius of curvature 6110 is equal to 0.5 inches, the second radius of curvature 6120 is equal to 0.0625 inches, and the third radius of curvature 6130 is equal to 0.125 inches.

Referring to Fig. 43, an expansion mandrel 6200 includes an internal flow passage 6205 having an insert 6210 including a flow passage 6215. The cross sectional area of the flow passage 6215 is less than the cross sectional area of the flow passage 6215. More generally, A plurality of inserts 6210 are provided, each with different sizes of flow passages 6215. In this manner, the flow passage 6215 is machined to a standard size, and the lubricant supply is varied by using different sized inserts 6210. The teachings of the expansion mandrel 6200 are incorporated into the expansion mandrels 5100, 5300, and 5600.

Referring to Fig. 44, The insert 6210 includes a filter 6305 for filtering particles and other foreign materials from the lubricant that passes into the flow passage 6205. In this manner, the foreign materials are prevented from clogging the flow passage 6205 and other flow passages within the expansion mandrel 6200.

The one or more of the lubrication systems and elements of the mandrels 5100, 5200, 5300, 5400, 5500, 5600, 5700, 5800 and/or 5900 are incorporated into the methods and apparatus for expanding tubular members described above with reference to FIGS. 1-30. In this manner, the amount of force required to radially expand a tubular member in the formation and/or repair of a wellbore casing, pipeline, or structural support is significantly reduced. Furthermore, the increased lubrication provided to the trail edge portion of the mandrel greatly reduces the amount of galling or seizure caused by the interface between the mandrel and the tubular member during the radial expansion process thereby permitting larger

continuous sections of tubulars to be radially expanded in a single continuous operation. Thus, use of the mandrels 5100, 5200, 5300, 5400, 5500, 5600, 5700, 5800 and/or 5900 reduces the operating pressures required for radial expansion and thereby reduces the sizes of the required hydraulic pumps and related equipment. In addition, failure, bursting, and/or buckling of tubular members during the radial expansion process is significantly reduced, and the success ratio of the radial expansion process is greatly increased.

In laboratory tests, a regular expansion cone, without any lubrication grooves and flow passages, and the expansion cone 5100 were both used to radially expand identical coiled tubular members, each having an outside diameter of 3 ½ inches. The following tables summarizes the results of this laboratory test:

LUBRICATING FLUID	REGULAR EXPANSION CONE	EXPANSION CONE 5100
	FORCE REQUIRED TO EXPAND TUBULAR MEMBER	
PHPA Mud alone	78,000 lbf	72,000 lbf
PHPA Mud + 7% Lubricant Blend	48,000 lbf	46,000 lbf
100% Lubricant Blend	68,000 lbf	48,000 lbf

Where: PHPA Mud refers to a drilling mud mixture available from Baroid.

PHPA Mud + 7 % Lubricant Blend refers to a mixture of 93% PHPA Mud and 7% mixture of TorqTrim III, EP Mudlib, and DrillN-Slid available from Baroid.

100% Lubricant Blend refers to a mixture of TorqTrim III, EP Mudlib, and DrillN-Slid available from Baroid.

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Thus, the use of the expansion cone 5100 reduced the amount of force required to radially expand a tubular member by as much as 30%. This reduction in the required force translates to a corresponding reduction in the overall energy requirements as well as a reduction in the size of required operating equipment such as, for example, hydraulic pumping equipment. During the course of a typical expansion operation, this results in tremendous cost savings to the operator.

The lubricating fluids used with the mandrels 5100, 5200, 5300, 5400, 5500, 5600, 5700, 5800 and 5900 for expanding tubular members have viscosities ranging from about 1 to 10,000 centipoise in order to optimize the injection of the lubricating fluids into the circumferential grooves of the mandrels during the radial expansion process.

Prior to placement in a wellbore, the outer surfaces of the apparatus for expanding tubular members described above with reference to FIGS. 1-30 are coated with a lubricating fluid to facilitate their placement the wellbore and reduce surge pressures. The lubricating fluid comprises BARO-LUB GOLD-SEAL™ brand drilling mud lubricant, available from Baroid Drilling Fluids, Inc. In this manner, the insertion of the apparatus into a wellbore, pipeline or other opening is optimized.

Referring to FIG. 45, an expandable tubular 6400 for use in forming and/or repairing a wellbore casing, pipeline, or foundation support will now be described. The expandable tubular 6400 includes a wall thickness T.

The wall thickness T is substantially constant throughout the expandable tubular 6400. The variation in the wall thickness T about the circumference of the tubular member 6400 is less than about 8 % in order to optimally provide an expandable tubular 6400 having a substantially constant hoop yield strength.

The material composition of and the manufacturing processes used in forming the expandable tubular 6400 are selected to provide a hoop yield strength that varies less than about 10 % about the circumference of the tubular member 6400 in order to optimally provide consistent geometries in the expandable tubular 6400 after radial expansion.

The expandable tubular 6400 includes structural imperfections such as, for example, voids, foreign material, cracks, of less than about 5 % of the specified wall

thickness T in order to optimize the radial expansion of the expandable tubular member 6400. Each expandable tubular 6400 is tested for the presence of such defects using nondestructive testing methods in accordance with industry standard API SR2.

A representative sample of a selected group of tubular members 6400 are flared at one end using a conventional industry standard tubular flaring method, such as, for example the method disclosed in ASTM A450. As illustrated in Fig. 46, The walls of the flared end of the tubular member 6400 do not exhibit any necking for increases in the interior diameter of the flared end 6405 of the tubular member 6400 ranging from 0 to about 25%. As illustrated in Fig. 47, The flared end of the tubular member 6400 does not fail for increases in the interior diameter of the flared end of the tubular members 6400 ranging from 0 to at least about 30%. In this manner, a selected group of tubular members 6400 are optimally selected for both necking and ductility properties subsequent to radial expansion.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features. Accordingly, it is appropriate that the appended claims be construed broadly and in a manner consistent with the scope of the invention.

CONVERSION TO METRIC UNITS

1.05 to 48 inches and 1/8 to 2 inches to 1.05 to 48 inches and 1/8 to 2 inches (2.667 to 121.92 and .3175 to 5.08 centimetres)

3.5 to 16 inches and 3/8 to 1.5 inches to 3.5 to 16 inches and 3/8 to 1.5 inches (8.89 to 40.64 centimetres and .9525 to 3.81)

2.5 to 50 inches to 2.5 to 50 inches (6.35 to 127 centimetres)

3.5 to 19 inches and 1/8 to 1.25 to 3.5 to 19 inches and 1/8 to 1.25 (8.89 to 48.26 and .3175 to 3.175 centimetres)

40 to 20,000 feet to 40 to 20,000 feet (12.192 to 6096.00 meters)

0 to 500 gallons/minute and 0 to 1,000 psi to 0 to 500 gallons/minute and 0 to 1,000 psi (0 to 1892.705 litres and 0 to 68.95 bar)

1,000 to 1,000,000 lbf to 1,000 to 1,000 000 lbf (.478803 to 478.803 bar)

40,000 to 135,000 psi to 40,000 to 135,000 psi (2757.90 to 9307.92 bar)

1.125 to 3 inches to 1.125 to 3 inches (2.857 to 7.62 centimetres)

0.25 to 0.75 to 0.25 to 0.75 (0.635 to 1.905 centimetres)

1,200 to 8,500 psi to 1,200 to 8,500 psi (82.737 to 586.054 bar)

40 to 1250 gallons/minute to 40 to 1250 gallons/minute (151.416 to 4,731.765 litres)

0 to 5 ft/sec. to 0 to 5 ft/sec. (0 to 1.524 meters)

0.75 to 47 inches and 1.05 to 48 inches to 0.75 to 47 inches and 1.05 to 48 inches (1.905 to 119.38 and 2.667 to 121.92 centimetres)

3 to 15.5 inches and 3.5 to 16 inches to 3 to 15.5 inches and 3.5 to 16 inches (7.62 to 39.37 and 8.89 to 40.64 centimetres)

240 to 480 inches to 240 to 480 inches (609.6 to 1219.2 centimetres)

0.1 to 0.5 inches to 0.1 to 0.5 inches (.254 to .127 centimetres)

0.025 to 0.375 inches to 0.025 to 0.375 inches (.0635 to .9525 centimetres)

0.025 to 0.125 inches to 0.025 to 0.125 inches (.0635 to .3175 centimetres)

100 to 1,000 psi to 100 to 1,000 psi (6.8947 to 68.947 bar)

2 to 34 inches to 2 to 34 inches (5.08 to 86.36 centimetres)

0 to 4,500 psi and 0 to 4,500 gallons/minute to 0 to 4,500 psi, and 0 to 4,500 gallons minute (0 to 310.264 bar, and 0 to 17034.35 litres)

0 to 3,500 psi, and 0 to 1,200 gallons/minute to 0 to 3,500 psi, and 0 to 1,200 gallons/minute (0 to 241.316 bar and 0 to 4542.49 litres)

0 to 4,500 psi, and 0 to 3,000 gallons/minute to 0 to 4,500 psi, and 0 to 3,000 gallons/minute (0 to 310.264 bar, and 0 to 11356.24 litres)

0 to 9,000 psi and 0 to 3,000 gallons/minute to 0 to 9,000 psi and 0 to 3,000 (0 to 620.528 bar and 0 to 11356.24 litres)

3 to 28 inches to 3 to 28 inches (7.62 to 71.12 centimetres)

0.0025 to 0.05 inches to 0.0025 to 0.05 inches (.00635 to .127 centimetres)

0 to 10,000 psi and 0 to 3,000 gallons/minute to 0 to 10,000 psi and 0 to 3,000 gallons/minute (0 to 689.476 bar and 0 to 11,356.24 litres)

0 to 12,000 psi and 0 to 3,500 gallons/minute to 0 to 12,000 psi and 0 to 3,500 gallons/minute (0 to 827.38 bar and 0 to 13,248.94 litres)

1,000 to 9,000 psi to 1,000 to 9,000 psi (68.95 to 620.53 bar)

78000 lbf to 78000 lbf (37.347 bar)

48000 lbf to 48000 lbf (22.983 bar)

68000 lbf to 68000 lbf (32.559 bar)

72000 lbf to 72000 lbf (34.474 bar)

46000 lbf to 46000 lbf (22.025 bar)

0 to 5,000 psi and 0 to 1,500 gallons/minute to 0 to 5,000 psi and 0 to 1,500 (0 to 344.738 bar and 0 to 5618.12 litres)

400 to 10,000 psi and 30 to 4,000 gallons/min to 400 to 10,000 psi and 30 to 4,000 gallons/min (27.58 to 689.476 bar and 113.56 to 15141.68 litres)

500 to 9,000 psi and 40 to 3,000 gallons/min to 500 to 9,000 psi and 40 to 3,000 gallons/min (34.47 to 620.53 bar and 151.42 to 11356.24 litres)

500 to 10,000 psi to 500 to 10,000 psi (34.47 to 689.48 bar)

50 to 2000 psi to 50 to 2000 psi (3.447 to 13.795 bar)

0.625 to 0.75 inches and 3 to 19 inches to 0.625 to 0.75 inches and 3 to 19 inches (1.5875 to 1.905 and 7.62 to 48.26 centimetres)

3/8 to 1.5 inches and 3.5 to 16 inches to 3/8 to 1.5 inches and 3.5 to 16 inches (.9525 to 3.81 and 8.89 to 40.64 centimetres)

THE FOLLOWING ARE REGISTERED TRADE MARKS

Teflon; and

Lubriplate

CLAIMS

1. A method of selecting a group of tubular members for subsequent radial expansion, comprising:

radially expanding the ends of a representative sample of the group of tubular members;

measuring the amount of necking of the walls of the radially expanded ends of the tubular members; and

if the radially expanded ends of the tubular members do not exhibit necking for radial expansions of up to 25%, then accepting the group of tubular members.

2. A method of selecting a group of tubular members, comprising:

radially expanding the ends of a representative sample of the group of tubular members until each of the tubular members fail;

if the radially expanded ends of the tubular members do not fail for radial expansions of up to 30%, then accepting the group of tubular members.

3. The method of claim 1 or 2, wherein at least one of the tubular members is placed in a borehole.

4. The method of claim 3, wherein the at least one of the tubular members is radially expanded and plastically deformed.

5. The method of claim 4, wherein the at least one of the tubular members is radially expanded and plastically deformed with an expansion cone.

6. The method of claim 5, wherein an interface between the expansion cone and the at least one of the tubular members is lubricated.

7. The method of claim 3, wherein the at least one of the tubular members is placed in a wellbore by injecting a lubricating fluid into the wellbore, and then inserting the tubular members into the wellbore.

8. The method of claim 3, wherein the at least one of the tubular members comprises a wellbore casing.

9. The method of claim 3, wherein the at least one of the tubular members comprises a pipeline.

10. The method of claim 3, wherein the at least one of the tubular members comprises a structural support.

11. The method of claim 3, wherein the at least one of the tubular members is radially expanded by positioning an expansion cone having a first tapered end and a second end at least partially within the tubular member; and pressurizing a region below the second end of the expansion cone, to force the expansion cone through the tubular member.

12. The method of claim 11, further comprising lubricating the interface between the tubular member and the expansion cone.

mandrels, 2735 and 2755, and expansion cone 2765. Throughout the radial expansion process, the upper end of the casing 2790 is preferably maintained in an overlapping relation with an existing section of wellbore casing.

At the end of the radial expansion process, the upper end of the casing 2790 is expanded into intimate contact with the inside surface of the lower end of the existing wellbore casing. The sealing members provided at the upper end of the casing 2790 provide a fluidic seal between the outside surface of the upper end of the casing 2790 and the inside surface of the lower end of the existing wellbore casing. The contact pressure between the casing 2790 and the existing section of wellbore casing ranges from about 400 to 10,000 in order to optimally provide contact pressure for activating the sealing members, provide optimal resistance to axial movement of the expanded casing, and optimally resist typical tensile and compressive loads on the expanded casing.

As the expansion cone 2765 nears the end of the casing 2790, the operating pressure of the second fluidic material is reduced in order to minimize shock to the apparatus 2700. The apparatus 2700 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 2790.

The reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 2765 nears the end of the casing 2790 in order to optimally provide reduced axial movement and velocity of the expansion cone 2765. The operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 2700 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 2765 during the return stroke. The stroke length of the apparatus 2700 ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and minimize the frequency at which the apparatus 2700 must be re-stroked during an expansion operation.

At least a portion of the upper sealing heads, 2725 and 2745, include expansion cones for radially expanding the mandrel launcher 2770 and casing 2790 during operation of the apparatus 2700 in order to increase the surface area of the casing 2790 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Mechanical slips are positioned in an axial location between the sealing sleeve 1915 and the first inner sealing mandrel 2720 in order to optimally provide a simplified assembly and operation of the apparatus 2700.

Upon the complete radial expansion of the casing 2790, if applicable, the first fluidic material is permitted to cure within the annular region between the outside of the expanded casing 2790 and the interior walls of the wellbore. In the case where the casing 2790 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 2790. In this manner, a new section of wellbore casing is formed within a wellbore. Alternatively, the apparatus 2700 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 2700 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 2700 may be used to expand a tubular support member in a hole.

During the radial expansion process, the pressurized areas of the apparatus 2700 are limited to the fluid passages 2795, 2800, 2802, 2805, and 2810, and the pressure chambers 2915 and 2920. No fluid pressure acts directly on the mandrel launcher 2770 and casing 2790. This permits the use of operating pressures higher than the mandrel launcher 2770 and casing 2790 could normally withstand.

Referring now to Figure 20, an apparatus 3000 for forming a mono-diameter wellbore casing will be described. The apparatus 3000 preferably includes a drillpipe 3005, an innerstring adapter 3010, a sealing sleeve 3015, a first inner sealing mandrel 3020, hydraulic slips 3025, a first upper sealing head 3030, a first lower sealing head 3035, a first outer sealing mandrel 3040, a second inner sealing mandrel 3045, a second upper sealing head 3050, a second lower sealing head 3055, a second outer sealing mandrel 3060, load mandrel 3065, expansion cone 3070, casing 3075, and fluid passages 3080, 3085, 3090, 3095, 3100, 3105, 3110, 3115 and 3120.

The drillpipe 3005 is coupled to the innerstring adapter 3010. During operation of the apparatus 3000, the drillpipe 3005 supports the apparatus 3000. The drillpipe 3005 preferably comprises a substantially hollow tubular member or members. The drillpipe 3005 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The drillpipe

3005 is fabricated from coiled tubing in order to facilitate the placement of the apparatus 3000 in non-vertical wellbores. The drillpipe 3005 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty threaded connection, or a standard threaded connection. The drillpipe 3005 is removably coupled to the innerstring adapter 3010 by a drillpipe connection.

The drillpipe 3005 preferably includes a fluid passage 3080 that is adapted to convey fluidic materials from a surface location into the fluid passage 3085. The fluid passage 3080 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The innerstring adapter 3010 is coupled to the drill string 3005 and the sealing sleeve 3015. The innerstring adapter 3010 preferably comprises a substantially hollow tubular member or members. The innerstring adapter 3010 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. The innerstring adapter 3010 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The innerstring adapter 3010 may be coupled to the drill string 3005 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. The innerstring adapter 3010 is removably coupled to the drill pipe 3005 by a drillpipe connection. The innerstring adapter 3010 may be coupled to the sealing sleeve 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The innerstring adapter 3010 is removably coupled to the sealing sleeve 3015 by a standard threaded connection.

The innerstring adapter 3010 preferably includes a fluid passage 3085 that is adapted to convey fluidic materials from the fluid passage 3080 into the fluid passage 3090. The fluid passage 3085 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The sealing sleeve 3015 is coupled to the innerstring adapter 3010 and the first inner sealing mandrel 3020. The sealing sleeve 3015 preferably comprises a substantially hollow tubular member or members. The sealing sleeve 3015 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The sealing sleeve 3015 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The sealing sleeve 3015 may be coupled to the innerstring adapter 3010 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. The sealing sleeve 3015 is removably coupled to the innerstring adapter 3010 by a standard threaded connection. The sealing sleeve 3015 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The sealing sleeve 3015 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection.

The sealing sleeve 3015 preferably includes a fluid passage 3090 that is adapted to convey fluidic materials from the fluid passage 3085 into the fluid passage 3095. The fluid passage 3090 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 is coupled to the sealing sleeve 3015, the hydraulic slips 3025, and the first lower sealing head 3035. The first inner sealing mandrel 3020 is further movably coupled to the first upper sealing head 3030. The

first inner sealing mandrel 3020 preferably comprises a substantially hollow tubular member or members. The first inner sealing mandrel 3020 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or similar high strength materials. The first inner sealing mandrel 3020 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first inner sealing mandrel 3020 may be coupled to the sealing sleeve 3015 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The first inner sealing mandrel 3020 is removably coupled to the sealing sleeve 3015 by a standard threaded connection. The first inner sealing mandrel 3020 may be coupled to the hydraulic slips 3025 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The first inner sealing mandrel 3020 is removably coupled to the hydraulic slips 3025 by a standard threaded connection. The first inner sealing mandrel 3020 may be coupled to the first lower sealing head 3035 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The first inner sealing mandrel 3020 is removably coupled to the first lower sealing head 3035 by a standard threaded connection.

The first inner sealing mandrel 3020 preferably includes a fluid passage 3095 that is adapted to convey fluidic materials from the fluid passage 3090 into the fluid passage 3100. The fluid passage 3095 is adapted to convey fluidic materials such as, for example, water, drilling mud, cement, epoxy, or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 further preferably includes fluid passages 3110 that are adapted to convey fluidic materials from the fluid passage 3095 into the

pressure chambers of the hydraulic slips 3025. In this manner, the slips 3025 are activated upon the pressurization of the fluid passage 3095 into contact with the inside surface of the casing 3075. The fluid passages 3110 are adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling fluids or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The first inner sealing mandrel 3020 further preferably includes fluid passages 3115 that are adapted to convey fluidic materials from the fluid passage 3095 into the first pressure chamber 3175 defined by the first upper sealing head 3030, the first lower sealing head 3035, the first inner sealing mandrel 3020, and the first outer sealing mandrel 3040. During operation of the apparatus 3000, pressurization of the pressure chamber 3175 causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 to move in an axial direction.

The slips 3025 are coupled to the outside surface of the first inner sealing mandrel 3020. During operation of the apparatus 3000, the slips 3025 are activated upon the pressurization of the fluid passage 3095 into contact with the inside surface of the casing 3075. In this manner, the slips 3025 maintain the casing 3075 in a substantially stationary position.

The slips 3025 preferably include fluid passages 3125, pressure chambers 3130, spring bias 3135, and slip members 3140. The slips 3025 may comprise any number of conventional commercially available hydraulic slips such as, for example, RTTS packer tungsten carbide hydraulic slips or Model 3L retrievable bridge plug with hydraulic slips. The slips 3025 comprise RTTS packer tungsten carbide hydraulic slips available from Halliburton Energy Services in order to optimally provide resistance to axial movement of the casing 3075 during the expansion process.

The first upper sealing head 3030 is coupled to the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070. The first upper sealing head 3030 is also movably coupled to the outer surface of the first inner sealing mandrel 3020 and the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, the first outer sealing

mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction.

The radial clearance between the inner cylindrical surface of the first upper sealing head 3030 and the outer surface of the first inner sealing mandrel 3020 may range, for example, from about 0.0025 to 0.05 inches. The radial clearance between the inner cylindrical surface of the first upper sealing head 3030 and the outer surface of the first inner sealing mandrel 3020 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the first upper sealing head 3030 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. The radial clearance between the outer cylindrical surface of the first upper sealing head 3030 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process.

The first upper sealing head 3030 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first upper sealing head 3030 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or other similar high strength materials. The first upper sealing head 3030 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the first upper sealing head 3030 preferably includes one or more annular sealing members 3145 for sealing the interface between the first upper sealing head 3030 and the first inner sealing mandrel 3020. The sealing members 3145 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3145 comprise polypak seals available from Parker seals in order to optimally provide sealing for a long axial stroke.

The first upper sealing head 3030 includes a shoulder 3150 for supporting the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the first lower sealing head 3035. The first upper sealing head 3030 may be coupled to the

first outer sealing mandrel 3040 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. The first upper sealing head 3030 is removably coupled to the first outer sealing mandrel 3040 by a standard threaded connection. The mechanical coupling between the first upper sealing head 3030 and the first outer sealing mandrel 3040 includes one or more sealing members 3155 for fluidicly sealing the interface between the first upper sealing head 3030 and the first outer sealing mandrel 3040. The sealing members 3155 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. The sealing members 3155 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head 3035 is coupled to the first inner sealing mandrel 3020 and the second inner sealing mandrel 3045. The first lower sealing head 3035 is also movably coupled to the inner surface of the first outer sealing mandrel 3040. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the first lower sealing head 3035 and the inner surface of the first outer sealing mandrel 3040 may range, for example, from about 0.0025 to 0.05 inches. The radial clearance between the outer surface of the first lower sealing head 3035 and the inner surface of the outer sealing mandrel 3040 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first lower sealing head 3035 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first lower sealing head 3035 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The first lower sealing head 3035 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the first lower sealing head 3035 preferably includes one or more annular sealing members 3160 for sealing the interface between the first lower sealing head 3035 and the first outer

sealing mandrel 3040. The sealing members 3160 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. The sealing members 3160 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first lower sealing head 3035 may be coupled to the first inner sealing mandrel 3020 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The first lower sealing head 3035 is removably coupled to the first inner sealing mandrel 3020 by a standard threaded connection. The mechanical coupling between the first lower sealing head 3035 and the first inner sealing mandrel 3020 includes one or more sealing members 3165 for fluidicly sealing the interface between the first lower sealing head 3035 and the first inner sealing mandrel 3020. The sealing members 3165 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. The sealing members 3165 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke length.

The first lower sealing head 3035 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The first lower sealing head 3035 is removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. The mechanical coupling between the first lower sealing head 3035 and the second inner sealing mandrel 3045 includes one or more sealing members 3170 for fluidicly sealing the interface between the first lower sealing head 3035 and the second inner sealing mandrel 3045. The sealing members 3170 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3170 comprise polypak seals

available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel 3040 is coupled to the first upper sealing head 3030 and the second upper sealing head 3050. The first outer sealing mandrel 3040 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the first lower sealing head 3035. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the first outer sealing mandrel 3040 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. The radial clearance between the outer surface of the first outer sealing mandrel 3040 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process. The radial clearance between the inner surface of the first outer sealing mandrel 3040 and the outer surface of the first lower sealing head 3035 may range, for example, from about 0.005 to 0.125 inches. The radial clearance between the inner surface of the first outer sealing mandrel 3040 and the outer surface of the first lower sealing head 3035 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The first outer sealing mandrel 3040 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The first outer sealing mandrel 3040 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The first outer sealing mandrel 3040 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The first outer sealing mandrel 3040 may be coupled to the first upper sealing head 3030 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The first outer sealing mandrel 3040 is removably coupled to the first upper sealing head 3030 by a standard threaded connection. The

mechanical coupling between the first outer sealing mandrel 3040 and the first upper sealing head 3030 includes one or more sealing members 3180 for sealing the interface between the first outer sealing mandrel 3040 and the first upper sealing head 3030. The sealing members 3180 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3180 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The first outer sealing mandrel 3040 may be coupled to the second upper sealing head 3050 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. The first outer sealing mandrel 3040 is removably coupled to the second upper sealing head 3050 by a standard threaded connection. The mechanical coupling between the first outer sealing mandrel 3040 and the second upper sealing head 3050 includes one or more sealing members 3185 for sealing the interface between the first outer sealing mandrel 3040 and the second upper sealing head 3050. The sealing members 3185 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3185 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second inner sealing mandrel 3045 is coupled to the first lower sealing head 3035 and the second lower sealing head 3055. The second inner sealing mandrel 3045 preferably comprises a substantially hollow tubular member or members. The second inner sealing mandrel 3045 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The second inner sealing mandrel 3045 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second inner sealing mandrel 3045 may be coupled to the first lower sealing head 3035 using any number of conventional commercially available

mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection or a standard threaded connection. The second inner sealing mandrel 3045 is removably coupled to the first lower sealing head 3035 by a standard threaded connection. The second inner sealing mandrel 3045 may be coupled to the second lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection, or a standard threaded connection. The second inner sealing mandrel 3045 is removably coupled to the second lower sealing head 3055 by a standard threaded connection.

The second inner sealing mandrel 3045 preferably includes a fluid passage 3100 that is adapted to convey fluidic materials from the fluid passage 3095 into the fluid passage 3105. The fluid passage 3100 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The second inner sealing mandrel 3045 further preferably includes fluid passages 3120 that are adapted to convey fluidic materials from the fluid passage 3100 into the second pressure chamber 3190 defined by the second upper sealing head 3050, the second lower sealing head 3055, the second inner sealing mandrel 3045, and the second outer sealing mandrel 3060. During operation of the apparatus 3000, pressurization of the second pressure chamber 3190 causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and the expansion cone 3070 to move in an axial direction.

The second upper sealing head 3050 is coupled to the first outer sealing mandrel 3040 and the second outer sealing mandrel 3060. The second upper sealing head 3050 is also movably coupled to the outer surface of the second inner sealing mandrel 3045 and the inner surface of the casing 3075. In this manner, the second upper sealing head 3050 reciprocates in the axial direction. The radial clearance between the inner cylindrical surface of the second upper sealing head 3050 and the outer surface of the second inner sealing mandrel 3045 may range, for example, from about 0.0025 to 0.05 inches. The radial clearance between the inner cylindrical surface

of the second upper sealing head 3050 and the outer surface of the second inner sealing mandrel 3045 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance. The radial clearance between the outer cylindrical surface of the second upper sealing head 3050 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. The radial clearance between the outer cylindrical surface of the second upper sealing head 3050 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process.

The second upper sealing head 3050 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second upper sealing head 3050 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The second upper sealing head 3050 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The inner surface of the second upper sealing head 3050 preferably includes one or more annular sealing members 3195 for sealing the interface between the second upper sealing head 3050 and the second inner sealing mandrel 3045. The sealing members 3195 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3195 comprise polypak seals available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second upper sealing head 3050 includes a shoulder 3200 for supporting the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 on the second lower sealing head 3055.

The second upper sealing head 3050 may be coupled to the first outer sealing mandrel 3040 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. The second upper sealing head 3050 is removably

coupled to the first outer sealing mandrel 3040 by a standard threaded connection. The mechanical coupling between the second upper sealing head 3050 and the first outer sealing mandrel 3040 includes one or more sealing members 3185 for fluidicly sealing the interface between the second upper sealing head 3050 and the first outer sealing mandrel 3040. The second upper sealing head 3050 may be coupled to the second outer sealing mandrel 3060 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type threaded connection, or a standard threaded connection. The second upper sealing head 3050 is removably coupled to the second outer sealing mandrel 3060 by a standard threaded connection. The mechanical coupling between the second upper sealing head 3050 and the second outer sealing mandrel 3060 includes one or more sealing members 3205 for fluidicly sealing the interface between the second upper sealing head 3050 and the second outer sealing mandrel 3060.

The second lower sealing head 3055 is coupled to the second inner sealing mandrel 3045 and the load mandrel 3065. The second lower sealing head 3055 is also movably coupled to the inner surface of the second outer sealing mandrel 3060. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing mandrel 3050, second outer sealing mandrel 3060, and expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 may range, for example, from about 0.0025 to 0.05 inches. The radial clearance between the outer surface of the second lower sealing head 3055 and the inner surface of the second outer sealing mandrel 3060 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second lower sealing head 3055 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second lower sealing head 3055 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel, or other similar high strength materials. The second lower sealing head 3055 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces. The outer surface of the second lower

sealing head 3055 preferably includes one or more annular sealing members 3210 for sealing the interface between the second lower sealing head 3055 and the second outer sealing mandrel 3060. The sealing members 3210 may comprise any number of conventional commercially available annular sealing members such as, for example, o-rings, polypak seals, or metal spring energized seals. The sealing members 3210 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the second inner sealing mandrel 3045 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. The second lower sealing head 3055 is removably coupled to the second inner sealing mandrel 3045 by a standard threaded connection. The mechanical coupling between the lower sealing head 3055 and the second inner sealing mandrel 3045 includes one or more sealing members 3215 for fluidicly sealing the interface between the second lower sealing head 3055 and the second inner sealing mandrel 3045. The sealing members 3215 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3215 comprise polypak seals available from Parker Seals in order to optimally provide sealing for long axial strokes.

The second lower sealing head 3055 may be coupled to the load mandrel 3065 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. The second lower sealing head 3055 is removably coupled to the load mandrel 3065 by a standard threaded connection. The mechanical coupling between the second lower sealing head 3055 and the load mandrel 3065 includes one or more sealing members 3220 for fluidicly sealing the interface between the second lower sealing head 3055 and the load mandrel 3065. The sealing members 3220 may comprise any number of conventional commercially available sealing members such as, for example, o-rings, polypak seals or metal spring energized seals. The sealing members 3220 comprise polypak seals

available from Parker Seals in order to optimally provide sealing for a long axial stroke.

The second lower sealing head 3055 includes a throat passage 3225 fluidicly coupled between the fluid passages 3100 and 3105. The throat passage 3225 is preferably of reduced size and is adapted to receive and engage with a plug 3230, or other similar device. In this manner, the fluid passage 3100 is fluidicly isolated from the fluid passage 3105. In this manner, the pressure chambers 3175 and 3190 are pressurized. Furthermore, the placement of the plug 3230 in the throat passage 3225 also pressurizes the pressure chambers 3130 of the hydraulic slips 3025.

The second outer sealing mandrel 3060 is coupled to the second upper sealing head 3050 and the expansion cone 3070. The second outer sealing mandrel 3060 is also movably coupled to the inner surface of the casing 3075 and the outer surface of the second lower sealing head 3055. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The radial clearance between the outer surface of the second outer sealing mandrel 3060 and the inner surface of the casing 3075 may range, for example, from about 0.025 to 0.375 inches. The radial clearance between the outer surface of the second outer sealing mandrel 3060 and the inner surface of the casing 3075 ranges from about 0.025 to 0.125 inches in order to optimally provide stabilization for the expansion cone 3070 during the expansion process. The radial clearance between the inner surface of the second outer sealing mandrel 3060 and the outer surface of the second lower sealing head 3055 may range, for example, from about 0.0025 to 0.05 inches. The radial clearance between the inner surface of the second outer sealing mandrel 3060 and the outer surface of the second lower sealing head 3055 ranges from about 0.005 to 0.01 inches in order to optimally provide minimal radial clearance.

The second outer sealing mandrel 3060 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The second outer sealing mandrel 3060 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials.

The second outer sealing mandrel 3060 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The second outer sealing mandrel 3060 may be coupled to the second upper sealing head 3050 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. The outer sealing mandrel 3060 is removably coupled to the second upper sealing head 3050 by a standard threaded connection. The second outer sealing mandrel 3060 may be coupled to the expansion cone 3070 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, or a standard threaded connection. The second outer sealing mandrel 3060 is removably coupled to the expansion cone 3070 by a standard threaded connection.

The first upper sealing head 3030, the first lower sealing head 3035, the first inner sealing mandrel 3020, and the first outer sealing mandrel 3040 together define the first pressure chamber 3175. The second upper sealing head 3050, the second lower sealing head 3055, the second inner sealing mandrel 3045, and the second outer sealing mandrel 3060 together define the second pressure chamber 3190. The first and second pressure chambers, 3175 and 3190, are fluidicly coupled to the passages, 3095 and 3100, via one or more passages, 3115 and 3120. During operation of the apparatus 3000, the plug 3230 engages with the throat passage 3225 to fluidicly isolate the fluid passage 3100 from the fluid passage 3105. The pressure chambers, 3175 and 3190, are then pressurized which in turn causes the first upper sealing head 3030, the first outer sealing mandrel 3040, the second upper sealing head 3050, the second outer sealing mandrel 3060, and expansion cone 3070 to reciprocate in the axial direction. The axial motion of the expansion cone 3070 in turn expands the casing 3075 in the radial direction. The use of a plurality of pressure chambers, 3175 and 3190, effectively multiplies the available driving force for the expansion cone 3070.

The load mandrel 3065 is coupled to the second lower sealing head 3055. The load mandrel 3065 preferably comprises an annular member having substantially cylindrical inner and outer surfaces. The load mandrel 3065 may be fabricated from any number of conventional commercially available materials such as, for example,

oilfield country tubular goods, low alloy steel, carbon steel, stainless steel or other similar high strength materials. The load mandrel 3065 is fabricated from stainless steel in order to optimally provide high strength, corrosion resistance, and low friction surfaces.

The load mandrel 3065 may be coupled to the lower sealing head 3055 using any number of conventional commercially available mechanical couplings such as, for example, epoxy, cement, water, drilling mud, or lubricants. The load mandrel 3065 is removably coupled to the lower sealing head 3055 by a standard threaded connection.

The load mandrel 3065 preferably includes a fluid passage 3105 that is adapted to convey fluidic materials from the fluid passage 3100 to the region outside of the apparatus 3000. The fluid passage 3105 is adapted to convey fluidic materials such as, for example, cement, epoxy, water, drilling mud or lubricants at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The expansion cone 3070 is coupled to the second outer sealing mandrel 3060. The expansion cone 3070 is also movably coupled to the inner surface of the casing 3075. In this manner, the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and the expansion cone 3070 reciprocate in the axial direction. The reciprocation of the expansion cone 3070 causes the casing 3075 to expand in the radial direction.

The expansion cone 3070 preferably comprises an annular member having substantially cylindrical inner and conical outer surfaces. The outside radius of the outside conical surface may range, for example, from about 2 to 34 inches. The outside radius of the outside conical surface ranges from about 3 to 28 inches in order to optimally provide an expansion cone 3070 for expanding typical casings. The axial length of the expansion cone 3070 may range, for example, from about 2 to 8 times the maximum outer diameter of the expansion cone 3070. The axial length of the expansion cone 3070 ranges from about 3 to 5 times the maximum outer diameter of the expansion cone 3070 in order to optimally provide stabilization and centralization of the expansion cone 3070 during the expansion process. The maximum outside diameter of the expansion cone 3070 is between about 95 to 99 % of the inside diameter of the existing wellbore that the casing 3075 will be joined with. The angle

of attack of the expansion cone 3070 ranges from about 5 to 30 degrees in order to optimally balance the frictional forces with the radial expansion forces.

The expansion cone 3070 may be fabricated from any number of conventional commercially available materials such as, for example, machine tool steel, nitride steel, titanium, tungsten carbide, ceramics, or other similar high strength materials. The expansion cone 3070 is fabricated from D2 machine tool steel in order to optimally provide high strength and resistance to wear and galling. The outside surface of the expansion cone 3070 has a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally provide high strength and resistance to wear and galling.

The expansion cone 3070 may be coupled to the second outside sealing mandrel 3060 using any number of conventional commercially available mechanical couplings such as, for example, drillpipe connection, oilfield country tubular goods specialty type threaded connection, ratchet-latch type connection or a standard threaded connection. The expansion cone 3070 is coupled to the second outside sealing mandrel 3060 using a standard threaded connection in order to optimally provide high strength and easy disassembly.

The casing 3075 is removably coupled to the slips 3025 and the expansion cone 3070. The casing 3075 preferably comprises a tubular member. The casing 3075 may be fabricated from any number of conventional commercially available materials such as, for example, slotted tubulars, oilfield country tubular goods, carbon steel, low alloy steel, stainless steel, or other similar high strength materials. The casing 3075 is fabricated from oilfield country tubular goods available from various foreign and domestic steel mills in order to optimally provide high strength.

The upper end 3235 of the casing 3075 includes a thin wall section 3240 and an outer annular sealing member 3245. The wall thickness of the thin wall section 3240 is about 50 to 100 % of the regular wall thickness of the casing 3075. In this manner, the upper end 3235 of the casing 3075 may be easily radially expanded and deformed into intimate contact with the lower end of an existing section of wellbore casing. The lower end of the existing section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section 3240 of casing 3075 into the thin walled section of the existing wellbore casing results in a wellbore casing having a substantially constant inside diameter.

The annular sealing member 3245 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. The annular sealing member 3245 is fabricated from StrataLock epoxy in order to optimally provide compressibility and wear resistance. The outside diameter of the annular sealing member 3245 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the wellbore casing that the casing 3075 is joined to. In this manner, after radial expansion, the annular sealing member 3245 optimally provides a fluidic seal and also preferably optimally provides sufficient frictional force with the inside surface of the existing section of wellbore casing during the radial expansion of the casing 3075 to support the casing 3075.

The lower end 3250 of the casing 3075 includes a thin wall section 3255 and an outer annular sealing member 3260. The wall thickness of the thin wall section 3255 is about 50 to 100 % of the regular wall thickness of the casing 3075. In this manner, the lower end 3250 of the casing 3075 may be easily expanded and deformed. Furthermore, in this manner, an other section of casing may be easily joined with the lower end 3250 of the casing 3075 using a radial expansion process. The upper end of the other section of casing also includes a thin wall section. In this manner, the radial expansion of the thin walled section of the upper end of the other casing into the thin walled section 3255 of the lower end 3250 of the casing 3075 results in a wellbore casing having a substantially constant inside diameter.

The upper annular sealing member 3245 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy, rubber, metal or plastic. The upper annular sealing member 3245 is fabricated from Stratalock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the upper annular sealing member 3245 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 3075 is joined to. In this manner, after radial expansion, the upper annular sealing member 3245 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 3075 to support the casing 3075.

The lower annular sealing member 3260 may be fabricated from any number of conventional commercially available sealing materials such as, for example, epoxy,

rubber, metal or plastic. The lower annular sealing member 3260 is fabricated from StrataLock epoxy in order to optimally provide compressibility and resistance to wear. The outside diameter of the lower annular sealing member 3260 preferably ranges from about 70 to 95 % of the inside diameter of the lower section of the existing wellbore casing that the casing 3075 is joined to. In this manner, the lower annular sealing member 3260 preferably provides a fluidic seal and also preferably provides sufficient frictional force with the inside wall of the wellbore during the radial expansion of the casing 3075 to support the casing 3075.

During operation, the apparatus 3000 is preferably positioned in a wellbore with the upper end 3235 of the casing 3075 positioned in an overlapping relationship with the lower end of an existing wellbore casing. The thin wall section 3240 of the casing 3075 is positioned in opposing overlapping relation with the thin wall section and outer annular sealing member of the lower end of the existing section of wellbore casing. In this manner, the radial expansion of the casing 3075 will compress the thin wall sections and annular compressible members of the upper end 3235 of the casing 3075 and the lower end of the existing wellbore casing into intimate contact. During the positioning of the apparatus 3000 in the wellbore, the casing 3000 is preferably supported by the expansion cone 3070.

After positioning the apparatus 3000, a first fluidic material is then pumped into the fluid passage 3080. The first fluidic material may comprise any number of conventional commercially available materials such as, for example, drilling mud, water, epoxy, cement, slag mix or lubricants. The first fluidic material comprises a hardenable fluidic sealing material such as, for example, cement, epoxy, or slag mix in order to optimally provide a hardenable outer annular body around the expanded casing 3075.

The first fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. The first fluidic material is pumped into the fluid passage 3080 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operating efficiency.

The first fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100, and 3105 and then outside of the apparatus

3000. The first fluidic material then preferably fills the annular region between the outside of the apparatus 3000 and the interior walls of the wellbore.

The plug 3230 is then introduced into the fluid passage 3080. The plug 3230 lodges in the throat passage 3225 and fluidicly isolates and blocks off the fluid passage 3100. A couple of volumes of a non-hardenable fluidic material are then pumped into the fluid passage 3080 in order to remove any hardenable fluidic material contained within and to ensure that none of the fluid passages are blocked.

A second fluidic material is then pumped into the fluid passage 3080. The second fluidic material may comprise any number of conventional commercially available materials such as, for example, water, drilling gases, drilling mud or lubricant. The second fluidic material comprises a non-hardenable fluidic material such as, for example, water, drilling mud, drilling gases, or lubricant in order to optimally provide pressurization of the pressure chambers 3175 and 3190.

The second fluidic material may be pumped into the fluid passage 3080 at operating pressures and flow rates ranging, for example, from about 0 to 4,500 psi and 0 to 4,500 gallons/minute. The second fluidic material is pumped into the fluid passage 3080 at operating pressures and flow rates ranging from about 0 to 3,500 psi and 0 to 1,200 gallons/minute in order to optimally provide operational efficiency.

The second fluidic material pumped into the fluid passage 3080 passes through the fluid passages 3085, 3090, 3095, 3100 and into the pressure chambers 3130 of the slips 3025, and into the pressure chambers 3175 and 3190. Continued pumping of the second fluidic material pressurizes the pressure chambers 3130, 3175, and 3190.

The pressurization of the pressure chambers 3130 causes the hydraulic slip members 3140 to expand in the radial direction and grip the interior surface of the casing 3075. The casing 3075 is then preferably maintained in a substantially stationary position.

The pressurization of the pressure chambers 3175 and 3190 cause the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 to move in an axial direction relative to the casing 3075. In this manner, the expansion cone 3070 will cause the casing 3075 to expand in the radial direction, beginning with the lower end 3250 of the casing 3075.

During the radial expansion process, the casing 3075 is prevented from moving in an upward direction by the slips 3025. A length of the casing 3075 is then expanded in the radial direction through the pressurization of the pressure chambers 3175 and 3190. The length of the casing 3075 that is expanded during the expansion process will be proportional to the stroke length of the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, and expansion cone 3070.

Upon the completion of a stroke, the operating pressure of the second fluidic material is reduced and the first upper sealing head 3030, first outer sealing mandrel 3040, second upper sealing head 3050, second outer sealing mandrel 3060, and expansion cone 3070 drop to their rest positions with the casing 3075 supported by the expansion cone 3070. The reduction in the operating pressure of the second fluidic material also causes the spring bias 3135 of the slips 3025 to pull the slip members 3140 away from the inside walls of the casing 3075.

The position of the drillpipe 3075 is preferably adjusted throughout the radial expansion process in order to maintain the overlapping relationship between the thin walled sections of the lower end of the existing wellbore casing and the upper end of the casing 3235. The stroking of the expansion cone 3070 is then repeated, as necessary, until the thin walled section 3240 of the upper end 3235 of the casing 3075 is expanded into the thin walled section of the lower end of the existing wellbore casing. In this manner, a wellbore casing is formed including two adjacent sections of casing having a substantially constant inside diameter. This process may then be repeated for the entirety of the wellbore to provide a wellbore casing thousands of feet in length having a substantially constant inside diameter.

During the final stroke of the expansion cone 3070, the slips 3025 are positioned as close as possible to the thin walled section 3240 of the upper end 3235 of the casing 3075 in order minimize slippage between the casing 3075 and the existing wellbore casing at the end of the radial expansion process. Alternatively, or in addition, the outside diameter of the upper annular sealing member 3245 is selected to ensure sufficient interference fit with the inside diameter of the lower end of the existing casing to prevent axial displacement of the casing 3075 during the final stroke. Alternatively, or in addition, the outside diameter of the lower annular sealing member 3260 is selected to provide an interference fit with the inside walls of the wellbore at

an earlier point in the radial expansion process so as to prevent further axial displacement of the casing 3075. In this final alternative, the interference fit is preferably selected to permit expansion of the casing 3075 by pulling the expansion cone 3070 out of the wellbore, without having to pressurize the pressure chambers 3175 and 3190.

During the radial expansion process, the pressurized areas of the apparatus 3000 are preferably limited to the fluid passages 3080, 3085, 3090, 3095, 3100, 3110, 3115, 3120, the pressure chambers 3130 within the slips 3025, and the pressure chambers 3175 and 3190. No fluid pressure acts directly on the casing 3075. This permits the use of operating pressures higher than the casing 3075 could normally withstand.

Once the casing 3075 has been completely expanded off of the expansion cone 3070, the remaining portions of the apparatus 3000 are removed from the wellbore. The contact pressure between the deformed thin wall sections and compressible annular members of the lower end of the existing casing and the upper end 3235 of the casing 3075 ranges from about 400 to 10,000 psi in order to optimally support the casing 3075 using the existing wellbore casing.

In this manner, the casing 3075 is radially expanded into contact with an existing section of casing by pressurizing the interior fluid passages 3080, 3085, 3090, 3095, 3100, 3110, 3115, and 3120, the pressure chambers 3130 of the slips 3025 and the pressure chambers 3175 and 3190 of the apparatus 3000.

As required, the annular body of hardenable fluidic material is then allowed to cure to form a rigid outer annular body about the expanded casing 3075. In the case where the casing 3075 is slotted, the cured fluidic material preferably permeates and envelops the expanded casing 3075. The resulting new section of wellbore casing includes the expanded casing 3075 and the rigid outer annular body. The overlapping joint between the pre-existing wellbore casing and the expanded casing 3075 includes the deformed thin wall sections and the compressible outer annular bodies. The inner diameter of the resulting combined wellbore casings is substantially constant. In this manner, a mono-diameter wellbore casing is formed. This process of expanding overlapping tubular members having thin wall end portions with compressible annular bodies into contact can be repeated for the entire length of a wellbore. In this manner,

a mono-diameter wellbore casing can be provided for thousands of feet in a subterranean formation.

As the expansion cone 3070 nears the upper end 3235 of the casing 3075, the operating flow rate of the second fluidic material is reduced in order to minimize shock to the apparatus 3000. The apparatus 3000 includes a shock absorber for absorbing the shock created by the completion of the radial expansion of the casing 3075.

The reduced operating pressure of the second fluidic material ranges from about 100 to 1,000 psi as the expansion cone 3070 nears the end of the casing 3075 in order to optimally provide reduced axial movement and velocity of the expansion cone 3070. The operating pressure of the second fluidic material is reduced during the return stroke of the apparatus 3000 to the range of about 0 to 500 psi in order minimize the resistance to the movement of the expansion cone 3070 during the return stroke. The stroke length of the apparatus 3000 ranges from about 10 to 45 feet in order to optimally provide equipment that can be easily handled by typical oil well rigging equipment and also minimize the frequency at which the apparatus 3000 must be re-stroked.

At least a portion of one or both of the upper sealing heads, 3030 and 3050, includes an expansion cone for radially expanding the casing 3075 during operation of the apparatus 3000 in order to increase the surface area of the casing 3075 acted upon during the radial expansion process. In this manner, the operating pressures can be reduced.

Alternatively, the apparatus 3000 may be used to join a first section of pipeline to an existing section of pipeline. Alternatively, the apparatus 3000 may be used to directly line the interior of a wellbore with a casing, without the use of an outer annular layer of a hardenable material. Alternatively, the apparatus 3000 may be used to expand a tubular support member in a hole.

Referring now to Figure 21, an apparatus 3330 for isolating subterranean zones will be described. A wellbore 3305 including a casing 3310 are positioned in a subterranean formation 3315. The subterranean formation 3315 includes a number of productive and non-productive zones, including a water zone 3320 and a targeted oil sand zone 3325. During exploration of the subterranean formation 3315, the wellbore 3305 may be extended in a well known manner to traverse the various productive and

non-productive zones, including the water zone 3320 and the targeted oil sand zone 3325.

In order to fluidicly isolate the water zone 3320 from the targeted oil sand zone 3325, an apparatus 3330 is provided that includes one or more sections of solid casing 3335, one or more external seals 3340, one or more sections of slotted casing 3345, one or more intermediate sections of solid casing 3350, and a solid shoe 3355.

The solid casing 3335 may provide a fluid conduit that transmits fluids and other materials from one end of the solid casing 3335 to the other end of the solid casing 3335. The solid casing 3335 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. The solid casing 3335 comprises oilfield tubulars available from various foreign and domestic steel mills.

The solid casing 3335 is preferably coupled to the casing 3310. The solid casing 3335 may be coupled to the casing 3310 using any number of conventional commercially available processes such as, for example, welding, slotted and expandable connectors, or expandable solid connectors. The solid casing 3335 is coupled to the casing 3310 by using expandable solid connectors. The solid casing 3335 may comprise a plurality of such solid casings 3335.

The solid casing 3335 is preferably coupled to one more of the slotted casings 3345. The solid casing 3335 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or slotted and expandable connectors. The solid casing 3335 is coupled to the slotted casing 3345 by expandable solid connectors.

The casing 3335 includes one more valve members 3360 for controlling the flow of fluids and other materials within the interior region of the casing 3335. During the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The casing 3335 is placed into the wellbore 3305 by expanding the casing 3335 in the radial direction into intimate contact with the interior walls of the wellbore 3305.

The casing 3335 may be expanded in the radial direction using any number of conventional commercially available methods. The casing 3335 is expanded in the radial direction using one or more of the processes and apparatus described within the present disclosure.

The seals 3340 prevent the passage of fluids and other materials within the annular region 3365 between the solid casings 3335 and 3350 and the wellbore 3305. The seals 3340 may comprise any number of conventional commercially available sealing materials suitable for sealing a casing in a wellbore such as, for example, lead, rubber or epoxy. The seals 3340 comprise Stratalok epoxy material available from Halliburton Energy Services.

The slotted casing 3345 permits fluids and other materials to pass into and out of the interior of the slotted casing 3345 from and to the annular region 3365. In this manner, oil and gas may be produced from a producing subterranean zone within a subterranean formation. The slotted casing 3345 may comprise any number of conventional commercially available sections of slotted tubular casing. The slotted casing 3345 comprises expandable slotted tubular casing available from Petroline in Aberdeen, Scotland. The slotted casing 145 comprises expandable slotted sandscreen tubular casing available from Petroline in Aberdeen, Scotland.

The slotted casing 3345 is preferably coupled to one or more solid casing 3335. The slotted casing 3345 may be coupled to the solid casing 3335 using any number of conventional commercially available processes such as, for example, welding, or slotted or solid expandable connectors. The slotted casing 3345 is coupled to the solid casing 3335 by expandable solid connectors.

The slotted casing 3345 is preferably coupled to one or more intermediate solid casings 3350. The slotted casing 3345 may be coupled to the intermediate solid casing 3350 using any number of conventional commercially available processes such as, for example, welding or expandable solid or slotted connectors. The slotted casing 3345 is coupled to the intermediate solid casing 3350 by expandable solid connectors.

The last section of slotted casing 3345 is preferably coupled to the shoe 3355. The last slotted casing 3345 may be coupled to the shoe 3355 using any number of conventional commercially available processes such as, for example, welding or

expandable solid or slotted connectors. The last slotted casing 3345 is coupled to the shoe 3355 by an expandable solid connector.

The shoe 3355 is coupled directly to the last one of the intermediate solid casings 3350.

The slotted casings 3345 are positioned within the wellbore 3305 by expanding the slotted casings 3345 in a radial direction into intimate contact with the interior walls of the wellbore 3305. The slotted casings 3345 may be expanded in a radial direction using any number of conventional commercially available processes. The slotted casings 3345 are expanded in the radial direction using one or more of the processes and apparatus disclosed in the present disclosure with reference to Figures 14a-20.

The intermediate solid casing 3350 permits fluids and other materials to pass between adjacent slotted casings 3345. The intermediate solid casing 3350 may comprise any number of conventional commercially available sections of solid tubular casing such as, for example, oilfield tubulars fabricated from chromium steel or fiberglass. The intermediate solid casing 3350 comprises oilfield tubulars available from foreign and domestic steel mills.

The intermediate solid casing 3350 is preferably coupled to one or more sections of the slotted casing 3345. The intermediate solid casing 3350 may be coupled to the slotted casing 3345 using any number of conventional commercially available processes such as, for example, welding, or solid or slotted expandable connectors. The intermediate solid casing 3350 is coupled to the slotted casing 3345 by expandable solid connectors. The intermediate solid casing 3350 may comprise a plurality of such intermediate solid casing 3350.

Each intermediate solid casing 3350 includes one more valve members 3370 for controlling the flow of fluids and other materials within the interior region of the intermediate casing 3350. As will be recognized by persons having ordinary skill in the art and the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing, sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

The intermediate casing 3350 is placed into the wellbore 3305 by expanding the intermediate casing 3350 in the radial direction into intimate contact with the interior walls of the wellbore 3305. The intermediate casing 3350 may be expanded in the radial direction using any number of conventional commercially available methods.

One or more of the intermediate solid casings 3350 may be omitted. One or more of the slotted casings 3345 are provided with one or more seals 3340.

The shoe 3355 provides a support member for the apparatus 3330. In this manner, various production and exploration tools may be supported by the show 3350. The shoe 3350 may comprise any number of conventional commercially available shoes suitable for use in a wellbore such as, for example, cement filled shoe, or an aluminum or composite shoe. The shoe 3350 comprises an aluminum shoe available from Halliburton. The shoe 3355 is selected to provide sufficient strength in compression and tension to permit the use of high capacity production and exploration tools.

The apparatus 3330 includes a plurality of solid casings 3335, a plurality of seals 3340, a plurality of slotted casings 3345, a plurality of intermediate solid casings 3350, and a shoe 3355. More generally, the apparatus 3330 may comprise one or more solid casings 3335, each with one or more valve members 3360, n slotted casings 3345, n-1 intermediate solid casings 3350, each with one or more valve members 3370, and a shoe 3355.

During operation of the apparatus 3330, oil and gas may be controllably produced from the targeted oil sand zone 3325 using the slotted casings 3345. The oil and gas may then be transported to a surface location using the solid casing 3335. The use of intermediate solid casings 3350 with valve members 3370 permits isolated sections of the zone 3325 to be selectively isolated for production. The seals 3340 permit the zone 3325 to be fluidicly isolated from the zone 3320. The seals 3340 further permits isolated ~~sections~~ of the zone 3325 to be fluidicly isolated from each other. In this manner, the apparatus 3330 permits unwanted and/or non-productive subterranean zones to be fluidicly isolated.

As will be recognized by persons having ordinary skill in the art and also having the benefit of the present disclosure, during the production mode of operation, an internal tubular string with various arrangements of packers, perforated tubing,

sliding sleeves, and valves may be employed within the apparatus to provide various options for commingling and isolating subterranean zones from each other while providing a fluid path to the surface.

Referring to Figures 22a, 22b, 22c and 22d, an apparatus 3500 for forming a wellbore casing while drilling a wellbore will now be described. The apparatus 3500 includes a support member 3505, a mandrel 3510, a mandrel launcher 3515, a shoe 3520, a tubular member 3525, a mud motor 3530, a drill bit 3535, a first fluid passage 3540, a second fluid passage 3545, a pressure chamber 3550, a third fluid passage 3555, a cup seal 3560, a body of lubricant 3565, seals 3570, and a releasable coupling 3600.

The support member 3505 is coupled to the mandrel 3510. The support member 3505 preferably comprises an annular member having sufficient strength to carry and support the apparatus 3500 within the wellbore 3575. The support member 3505 further includes one or more conventional centralizers (not illustrated) to help stabilize the apparatus 3500.

The support member 3505 may comprise one or more sections of conventional commercially available tubular materials such as, for example, oilfield country tubular goods, low alloy steel, stainless steel or carbon steel. The support member 3505 comprises coiled tubing or drillpipe in order to optimally permit the placement of the apparatus 3500 within a non-vertical wellbore.

The support member 3505 includes a first fluid passage 3540 for conveying fluidic materials from a surface location to the fluid passage 3545. The first fluid passage 3540 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 10,000 psi and 0 to 3,000 gallons/minute.

The mandrel 3510 is coupled to and supported by the support member 3505. The mandrel 3510 is also coupled to and supports the mandrel launcher 3515 and tubular member 3525. The mandrel 3510 is preferably adapted to controllably expand in a radial direction. The mandrel 3510 may comprise any number of conventional commercially available mandrels modified in accordance with the teachings of the present disclosure. The mandrel 3510 comprises a hydraulic expansion tool as

disclosed in U.S. Patent No. 5,348,095, the contents of which are incorporated herein by reference, modified in accordance with the teachings of the present disclosure.

The mandrel 3510 includes one or more conical sections for expanding the tubular member 3525 in the radial direction. The outer surfaces of the conical sections of the mandrel 3510 have a surface hardness ranging from about 58 to 62 Rockwell C in order to optimally radially expand the tubular member 3525.

The mandrel 3510 includes a second fluid passage 3545 fluidicly coupled to the first fluid passage 3540 and the pressure chamber 3550 for conveying fluidic materials from the first fluid passage 3540 to the pressure chamber 3550. The second fluid passage 3545 is adapted to convey fluidic materials such as water, drilling mud, cement, epoxy or slag mix at operating pressures and flow rates ranging from about 0 to 12,000 psi and 0 to 3,500 gallons/minute in order to optimally provide operating pressure for efficient operation.

The mandrel launcher 3515 is coupled to the tubular member 3525, the mandrel 3510, and the shoe 3520. The mandrel launcher 3515 preferably comprises a tapered annular member that mates with at a portion of at least one of the conical portions of the outer surface of the mandrel 3510. The wall thickness of the mandrel launcher is less than the wall thickness of the tubular member 3525 in order to facilitate the initiation of the radial expansion process and facilitate the placement of the apparatus in openings having tight clearances. The wall thickness of the mandrel launcher 3515 ranges from about 50 to 100 % of the wall thickness of the tubular member 3525 immediately adjacent to the mandrel launcher 3515 in order to optimally facilitate the radial expansion process and facilitate the insertion of the apparatus 3500 into wellbore casings and other areas with tight clearances.

The mandrel launcher 3515 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel or stainless steel. The mandrel launcher 3515 is fabricated from oilfield country tubular goods of higher strength by lower wall thickness than the tubular member 3525 in order to optimally provide a smaller container having approximately the same burst strength as the tubular member 3525.

The shoe 3520 is coupled to the mandrel launcher 3515 and the releasable coupling 3600. The shoe 3520 preferably comprises a substantially annular member.

The shoe 3520 or the releasable coupling 3600 include a third fluid passage 3555 fluidicly coupled to the pressure chamber 3550 and the mud motor 3530.

The shoe 3520 may comprise any number of conventional commercially available shoes such as, for example, cement filled, aluminum or composite modified in accordance with the teachings of the present disclosure. The shoe 3520 comprises a high strength shoe having a burst strength approximately equal to the burst strength of the tubular member 3525 and mandrel launcher 3515. The shoe 3520 is preferably coupled to the mud motor 3520 by a releasable coupling 3600 in order to optimally provide for removal of the mud motor 3530 and drill nit 3535 upon the completion of a drilling and casing operation.

The shoe 3520 includes a releasable latch mechanism 3600 for retrieving and removing the mud motor 3530 and drill bit 3535 upon the completion of the drilling and casing formation operations. The shoe 3520 further includes an anti-rotation device for maintaining the shoe 3520 in a substantially stationary rotational position during operation of the apparatus 3500. The releasable latch mechanism 3600 is releasably coupled to the shoe 3520.

The tubular member 3525 is supported by and coupled to the mandrel 3510. The tubular member 3525 is expanded in the radial direction and extruded off of the mandrel 3510. The tubular member 3525 may be fabricated from any number of conventional commercially available materials such as, for example, Oilfield Country Tubular Goods (OCTG), 13 chromium steel tubing/casing, automotive grade steel, or plastic tubing/casing. The tubular member 3525 is fabricated from OCTG in order to maximize strength after expansion. The inner and outer diameters of the tubular member 3525 may range, for example, from approximately 0.75 to 47 inches and 1.05 to 48 inches, respectively. The inner and outer diameters of the tubular member 3525 range from about 3 to 15.5 inches and 3.5 to 16 inches, respectively in order to optimally provide minimal telescoping effect in the most commonly drilled wellbore sizes. The tubular member 3525 preferably comprises an annular member with solid walls.

The upper end portion 3580 of the tubular member 3525 is slotted, perforated, or otherwise modified to catch or slow down the mandrel 3510 when the mandrel 3510 completes the extrusion of tubular member 3525. For typical tubular member 3525

materials, the length of the tubular member 3525 is preferably limited to between about 40 to 20,000 feet in length. The tubular member 3525 may comprise a single tubular member or, alternatively, a plurality of tubular members coupled to one another.

The mud motor 3530 is coupled to the shoe 3520 and the drill bit 3535. The mud motor 3530 is also fluidicly coupled to the fluid passage 3555. The mud motor 3530 is driven by fluidic materials such as, for example, drilling mud, water, cement, epoxy, lubricants or slag mix conveyed from the fluid passage 3555 to the mud motor 3530. In this manner, the mud motor 3530 drives the drill bit 3535. The operating pressures and flow rates for operating mud motor 3530 may range, for example, from about 0 to 12,000 psi and 0 to 10,000 gallons/minute. The operating pressures and flow rates for operating mud motor 3530 range from about 0 to 5,000 psi and 40 to 3,000 gallons/minute.

The mud motor 3530 may comprise any number of conventional commercially available mud motors, modified in accordance with the teachings of the present disclosure. The size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the drilling and casing operations.

The drill bit 3535 is coupled to the mud motor 3530. The drill bit 3535 is preferably adapted to be powered by the mud motor 3530. In this manner, the drill bit 3535 drills out new sections of the wellbore 3575.

The drill bit 3535 may comprise any number of conventional commercially available drill bits, modified in accordance with the teachings of the present disclosure. The size of the mud motor 3520 and drill bit 3535 are selected to pass through the interior of the shoe 3520 and the expanded tubular member 3525. In this manner, the mud motor 3520 and drill bit 3535 may be retrieved from the downhole location upon the conclusion of the drilling and casing operations. The drill bit 3535 comprises an eccentric drill bit, a bi-centered drill bit, or a small diameter drill bit with an hydraulically actuated under reamer.

The first fluid passage 3540 permits fluidic materials to be transported to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555,

and the mud motor 3530. The first fluid passage 3540 is coupled to and positioned within the support member 3505. The first fluid passage 3540 preferably extends from a position adjacent to the surface to the second fluid passage 3545 within the mandrel 3510. The first fluid passage 3540 is preferably positioned along a centerline of the apparatus 3500.

The second fluid passage 3545 permits fluidic materials to be conveyed from the first fluid passage 3540 to the pressure chamber 3550, the third fluid passage 3555, and the mud motor 3530. The second fluid passage 3545 is coupled to and positioned within the mandrel 3510. The second fluid passage 3545 preferably extends from a position adjacent to the first fluid passage 3540 to the bottom of the mandrel 3510. The second fluid passage 3545 is preferably positioned substantially along the centerline of the apparatus 3500.

The pressure chamber 3550 permits fluidic materials to be conveyed from the second fluid passage 3545 to the third fluid passage 3555, and the mud motor 3530. The pressure chamber is preferably defined by the region below the mandrel 3510 and within the tubular member 3525, mandrel launcher 3515, shoe 3520, and releasable coupling 3600. During operation of the apparatus 3500, pressurization of the pressure chamber 3550 preferably causes the tubular member 3525 to be extruded off of the mandrel 3510.

The third fluid passage 3555 permits fluidic materials to be conveyed from the pressure chamber 3550 to the mud motor 3530. The third fluid passage 3555 may be coupled to and positioned within the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 preferably extends from a position adjacent to the pressure chamber 3550 to the bottom of the shoe 3520 or releasable coupling 3600. The third fluid passage 3555 is preferably positioned substantially along the centerline of the apparatus 3500.

The fluid passages 3540, 3545, and 3555 are preferably selected to convey materials such as cement, drilling mud or epoxies at flow rates and pressures ranging from about 0 to 3,000 gallons/minute and 0 to 9,000 psi in order to optimally operational efficiency.

The cup seal 3560 is coupled to and supported by the outer surface of the support member 3505. The cup seal 3560 prevents foreign materials from entering the

interior region of the tubular member 3525. The cup seal 3560 may comprise any number of conventional commercially available cup seals such as, for example, TP cups or SIP cups modified in accordance with the teachings of the present disclosure. The cup seal 3560 comprises a SIP cup, available from Halliburton Energy Services in Dallas, TX in order to optimally block the entry of foreign materials and contain a body of lubricant. The apparatus 3500 includes a plurality of such cup seals in order to optimally prevent the entry of foreign material into the interior region of the tubular member 3525 in the vicinity of the mandrel 3510.

A quantity of lubricant 3565 is provided in the annular region above the mandrel 3510 within the interior of the tubular member 3525. In this manner, the extrusion of the tubular member 3525 off of the mandrel 3510 is facilitated. The lubricant 3565 may comprise any number of conventional commercially available lubricants such as, for example, Lubriplate, chlorine based lubricants, oil based lubricants or Climax 1500 Antisieze (3100). The lubricant 3565 comprises Climax 1500 Antisieze (3100) available from Climax Lubricants and Equipment Co. in Houston, TX in order to optimally provide optimum lubrication to facilitate the expansion process.

The seals 3570 are coupled to and supported by the end portion 3580 of the tubular member 3525. The seals 3570 are further positioned on an outer surface of the end portion 3580 of the tubular member 3525. The seals 3570 permit the overlapping joint between the lower end portion 3585 of a preexisting section of casing 3590 and the end portion 3580 of the tubular member 3525 to be fluidicly sealed. The seals 3570 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon, or epoxy seals modified in accordance with the teachings of the present disclosure. The seals 3570 are molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a load bearing interference fit between the end 3580 of the tubular member 3525 and the end 3585 of the pre-existing casing 3590.

The seals 3570 are selected to optimally provide a sufficient frictional force to support the expanded tubular member 3525 from the pre-existing casing 3590. The frictional force optimally provided by the seals 3570 ranges from about 1,000 to 1,000,000 lbf in order to optimally support the expanded tubular member 3525.

The releasable coupling 3600 is preferably releasably coupled to the bottom of the shoe 3520. The releasable coupling 3600 includes fluidic seals for sealing the interface between the releasable coupling 3600 and the shoe 3520. In this manner, the pressure chamber 3550 may be pressurized. The releasable coupling 3600 may comprise any number of conventional commercially available releasable couplings suitable for drilling operations modified in accordance with the teachings of the present disclosure.

As illustrated in Figure 22A, during operation of the apparatus 3500, the apparatus 3500 is preferably initially positioned within a preexisting section of a wellbore 3575 including a preexisting section of wellbore casing 3590. The upper end portion 3580 of the tubular member 3525 is positioned in an overlapping relationship with the lower end 3585 of the preexisting section of casing 3590. The apparatus 3500 is initially positioned in the wellbore 3575 with the drill bit 353 in contact with the bottom of the wellbore 3575. During the initial placement of the apparatus 3500 in the wellbore 3575, the tubular member 3525 is preferably supported by the mandrel 3510.

As illustrated in Figure 22B, a fluidic material 3595 is then pumped into the first fluid passage 3540. The fluidic material 3595 is preferably conveyed from the first fluid passage 3540 to the second fluid passage 3545, the pressure chamber 3550, the third fluid passage 3555 and the inlet to the mud motor 3530. The fluidic material 3595 may comprise any number of conventional commercially available fluidic materials such as, for example, drilling mud, water, cement, epoxy or slag mix. The fluidic material 3595 may be pumped into the first fluid passage 3540 at operating pressures and flow rates ranging, for example, from about 0 to 9,000 psi and 0 to 3,000 gallons/minute.

The fluidic material 3595 will enter the inlet for the mud motor 3530 and drive the mud motor 3530. The fluidic material 3595 will then exit the mud motor 3530 and enter the annular region surrounding the apparatus 3500 within the wellbore 3575. The mud motor 3530 will in turn drive the drill bit 3535. The operation of the drill bit 3535 will drill out a new section of the wellbore 3575.

In the case where the fluidic material 3595 comprises a hardenable fluidic material, the fluidic material 3595 preferably is permitted to cure and form an outer annular body surrounding the periphery of the expanded tubular member 3525.

Alternatively, in the case where the fluidic material 3595 is a non-hardenable fluidic material, the tubular member 3595 preferably is expanded into intimate contact with the interior walls of the wellbore 3575. In this manner, an outer annular body is not provided in all applications.

As illustrated in Figure 22C, at some point during operation of the mud motor 3530 and drill bit 3535, the pressure drop across the mud motor 3530 will create sufficient back pressure to cause the operating pressure within the pressure chamber 3550 to elevate to the pressure necessary to extrude the tubular member 3525 off of the mandrel 3510. The elevation of the operating pressure within the pressure chamber 3550 will then cause the tubular member 3525 to extrude off of the mandrel 3510 as illustrated in Figure 22D. For typical tubular members 3525, the necessary operating pressure may range, for example, from about 1,000 to 9,000 psi. In this manner, a wellbore casing is formed simultaneous with the drilling out of a new section of wellbore.

During the operation of the apparatus 3500, the apparatus 3500 is lowered into the wellbore 3575 until the drill bit 3535 is proximate the bottom of the wellbore 3575. Throughout this process, the tubular member 3525 is preferably supported by the mandrel 3510. The apparatus 3500 is then lowered until the drill bit 3535 is placed in contact with the bottom of the wellbore 3575. At this point, at least a portion of the weight of the tubular member 3525 is supported by the drill bit 3535.

The fluidic material 3595 is then pumped into the first fluid passage 3540, second fluid passage 3545, pressure chamber 3550, third fluid passage 3555, and the inlet of the mud motor 3530. The mud motor 3530 then drives the drill bit 3535 to drill out a new section of the wellbore 3575. Once the differential pressure across the mud motor 3530 exceeds the minimum extrusion pressure for the tubular member 3525, the tubular member 3525 begins to extrude off of the mandrel 3510. As the tubular member 3525 is extruded off of the mandrel 3510, the weight of the extruded portion of the tubular member 3525 is transferred to and supported by the drill bit 3535. The pumping pressure of the fluidic material 3595 is maintained substantially constant throughout this process. At some point during the process of extruding the tubular member 3525 off of the mandrel 3510, a sufficient portion of the weight of the tubular member 3525 is transferred to the drill bit 3535 to stop the extrusion process

due to the opposing force. Continued drilling by the drill bit 3535 eventually transfers a sufficient portion of the weight of the extruded portion of the tubular member 3525 back to the mandrel 3510. At this point, the extrusion of the tubular member 3525 off of the mandrel 3510 continues. In this manner, the support member 3505 never has to be moved and no drillpipe connections have to be made at the surface since the new section of the wellbore casing within the newly drilled section of wellbore is created by the constant downward feeding of the expanded tubular member 3525 off of the mandrel 3510.

Once the new section of wellbore that is lined with the fully expanded tubular member 3525 is completed, the support member 3505 and mandrel 3510 are removed from the wellbore 3575. The drilling assembly including the mud motor 3530 and drill bit 3535 are then preferably removed by lowering a drillstring into the new section of wellbore casing and retrieving the drilling assembly by using the latch 3600. The expanded tubular member 3525 is then cemented using conventional squeeze cementing methods to provide a solid annular sealing member around the periphery of the expanded tubular member 3525.

Alternatively, the apparatus 3500 may be used to repair or form an underground pipeline or form a support member for a structure. The teachings of the apparatus 3500 are combined with the teachings illustrated in Figures 1-21. For example, by operably coupling the mud motor 3530 and drill bit 3535 to the pressure chambers used to cause the radial expansion of the tubular members of the arrangements illustrated and described with reference to Figures 1-21, the use of plugs may be eliminated and radial expansion of tubular members can be combined with the drilling out of new sections of wellbore.

Referring now to FIGS. 23A, 23B and 23C, an apparatus 3700 for expanding a tubular member will be described. The apparatus 3700 includes a support member 3705, a packer 3710, a first fluid conduit 3715, an annular fluid passage 3720, fluid inlets 3725, an annular seal 3730, a second fluid conduit 3735, a fluid passage 3740, a mandrel 3745, a mandrel launcher 3750, a tubular member 3755, slips 3760, and seals 3765. The apparatus 3700 is used to radially expand the tubular member 3755. In this manner, the apparatus 3700 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a

wellbore casing, pipeline or structural support member. The apparatus 3700 is used to clad at least a portion of the tubular member 3755 onto a preexisting tubular member.

The support member 3705 is preferably coupled to the packer 3710 and the mandrel launcher 3750. The support member 3705 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3705 is preferably selected to fit through a preexisting section of wellbore casing 3770. In this manner, the apparatus 3700 may be positioned within the wellbore casing 3770. The support member 3705 is releasably coupled to the mandrel launcher 3750. In this manner, the support member 3705 may be decoupled from the mandrel launcher 3750 upon the completion of an extrusion operation.

The packer 3710 is coupled to the support member 3705 and the first fluid conduit 3715. The packer 3710 preferably provides a fluid seal between the outside surface of the first fluid conduit 3715 and the inside surface of the support member 3705. In this manner, the packer 3710 preferably seals off and, in combination with the support member 3705, first fluid conduit 3715, second fluid conduit 3735, and mandrel 3745, defines an annular chamber 3775. The packer 3710 may comprise any number of conventional commercially available packers modified in accordance with the teachings of the present disclosure.

The first fluid conduit 3715 is coupled to the packer 3710 and the annular seal 3730. The first fluid conduit 3715 preferably comprises an annular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The first fluid conduit 3715 includes one or more fluid inlets 3725 for conveying fluidic materials from the annular fluid passage 3720 into the chamber 3775.

The annular fluid passage 3720 is defined by and positioned between the interior surface of the first fluid conduit 3715 and the interior surface of the second fluid conduit 3735. The annular fluid passage 3720 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid inlets 3725 are positioned in an end portion of the first fluid conduit 3715. The fluid inlets 3725 preferably are adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The annular seal 3730 is coupled to the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735. The annular seal 3730 preferably provides a fluid seal between the interior surface of the first fluid conduit 3715 and the exterior surface of the second fluid conduit 3735 during relative axial motion of the first fluid conduit 3715 and the second fluid conduit 3735. The annular seal 3730 may comprise any number of conventional commercially available seals such as, for example, o-rings, polypak seals or metal spring energized seals. The annular seal 3730 comprises a polypak seal available from Parker Seals in order to optimally provide sealing for axial motion.

The second fluid conduit 3735 is coupled to the annular seal 3730 and the mandrel 3745. The second fluid conduit preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, coiled tubing, oilfield country tubular goods, low alloy steel, stainless steel, or low carbon steel. The second fluid conduit 3735 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The fluid passage 3740 is coupled to the second fluid conduit 3735 and the mandrel 3745. The fluid passage 3740 is adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency.

The mandrel 3745 is coupled to the second fluid conduit 3735 and the mandrel launcher 3750. The mandrel 3745 preferably comprise an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, carbon steel, tool steel, ceramics, or composite

materials. The angle of attack the conic section of the mandrel 3745 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3750 and tubular member 3755 in the radial direction. The surface hardness of the conic section of the mandrel 3745 ranges from about 50 Rockwell C to 70 Rockwell C. The surface hardness of the outer surface of the conic section of the mandrel 3745 ranges from about 58 Rockwell C to 62 Rockwell C in order to optimally provide high yield strength. The mandrel 3745 is expandable in order to further optimally augment the radial expansion process.

The mandrel launcher 3750 is coupled to the support member 3705, the mandrel 3745, and the tubular member 3755. The mandrel launcher 3750 preferably comprise a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. The cross-sectional area of the mandrel launcher 3750 at one end is adapted to mate with the mandrel 3745, and at the other end, the cross-sectional area of the mandrel launcher 3750 is adapted to match the cross-sectional area of the tubular member 3755. The wall thickness of the mandrel launcher 3750 ranges from about 50 to 100 % of the wall thickness of the tubular member 3755 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 3750 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low allow steel, stainless steel, or carbon steel. The mandrel launcher 3750 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 3755 in order to optimally match the burst strength of the tubular member 3755. The mandrel launcher 3750 is removably coupled to the tubular member 3755. In this manner, the mandrel launcher 3750 may be removed from the wellbore 3780 upon the completion of an extrusion operation.

The tubular member 3755 is coupled to the mandrel launcher, the slips 3760 and the seals 3765. The tubular member 3755 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. The tubular member 3755 is fabricated from oilfield country tubular goods.

The slips 3760 are coupled to the outside surface of the tubular member 3755. The slips 3760 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3755. In this manner, the slips 3760 provide structural support for the expanded tubular member 3755. The slips 3760 may comprise any number of conventional commercially available slips, modified in accordance with the teachings of the present disclosure.

The seals 3765 are coupled to the outside surface of the tubular member 3755. The seals 3765 preferably provide a fluidic seal between the outside surface of the expanded tubular member 3755 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3755. In this manner, the seals 3765 provide a fluidic seal for the expanded tubular member 3755. The seals 3765 may comprise any number of conventional commercially available seals such as, for example, lead, rubber, Teflon or epoxy seals modified in accordance with the teachings of the present disclosure. The seals 3765 comprise seals molded from Stratalock epoxy available from Halliburton Energy Services in Dallas, TX in order to optimally provide a hydraulic seal in the overlapping joint and optimally provide load carrying capacity to withstand the range of typical tensile and compressive loads.

During operation of the apparatus 3700, the apparatus 3700 is preferably lowered into a wellbore 3780 having a preexisting section of wellbore casing 3770. The apparatus 3700 is positioned with at least a portion of the tubular member 3755 overlapping with a portion of the wellbore casing 3770. In this manner, the radial expansion of the tubular member 3755 will preferably cause the outside surface of the expanded tubular member 3755 to couple with the inside surface of the wellbore casing 3770. The radial expansion of the tubular member 3755 will also cause the slips 3760 and seals 3765 to engage with the interior surface of the wellbore casing 3770. In this manner, the expanded tubular member 3755 is provided with enhanced structural support by the slips 3760 and an enhanced fluid seal by the seals 3765.

As illustrated in FIG. 23B, after placement of the apparatus 3700 in an overlapping relationship with the wellbore casing 3770, a fluidic material 3785 is preferably pumped into the chamber 3775 using the fluid passage 3720 and the inlet passages 3725. The fluidic material is pumped into the chamber 3775 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000

gallons/minute in order to optimally provide operational efficiency. The pumped fluidic material 3785 increase the operating pressure within the chamber 3775. The increased operating pressure in the chamber 3775 then causes the mandrel 3745 to extrude the mandrel launcher 3750 and tubular member 3755 off of the face of the mandrel 3745. The extrusion of the mandrel launcher 3750 and tubular member 3755 off of the face of the mandrel 3745 causes the mandrel launcher 3750 and tubular member 3755 to expand in the radial direction. Continued pumping of the fluidic material 3785 preferably causes the entire length of the tubular member 3755 to expand in the radial direction.

The pumping rate and pressure of the fluidic material 3785 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 3700. The apparatus 3700 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process.

The extrusion process causes the mandrel 3745 to move in an axial direction 3785. During the axial movement of the mandrel, The fluid passage 3740 conveys fluidic material 3790 displaced by the moving mandrel 3745 out of the wellbore 3780. In this manner, the operational efficiency and speed of the extrusion process is enhanced.

The extrusion process includes the injection of a hardenable fluidic material into the annular region between the tubular member 3755 and the bore hole 3780. In this manner, a hardened sealing layer is provided between the expanded tubular member 3755 and the interior walls of the wellbore 3780.

As illustrated in FIG. 23C, Upon the completion of the extrusion process, the support member 3705, packer 3710, first fluid conduit 3715, annular seal 3730, second fluid conduit 3735, mandrel 3745, and mandrel launcher 3750 are moved from the wellbore 3780.

The apparatus 3700 is used to repair a preexisting wellbore casing, pipeline, or structural support. Both ends of the tubular member 3755 preferably include slips 3760 and seals 3765.

The apparatus 3700 is used to form a tubular structural support for a building or offshore structure.

Referring now to FIGS. 24A, 24B, 24C, 24D, and 24E, an apparatus 3900 for expanding a tubular member will be described. The apparatus 3900 includes a support member 3905, a mandrel launcher 3910, a mandrel 3915, a first fluid passage 3920, a tubular member 3925, slips 3930, seals 3935, a shoe 3940, and a second fluid passage 3945. The apparatus 3900 is used to radially expand the mandrel launcher 3910 and tubular member 3925. In this manner, the apparatus 3900 may be used to form a wellbore casing, line a wellbore casing, form a pipeline, line a pipeline, form a structural support member, or repair a wellbore casing, pipeline or structural support member. The apparatus 3900 is used to clad at least a portion of the tubular member 3925 onto a preexisting structural member.

The support member 3905 is preferably coupled to the mandrel launcher 3910. The support member 3905 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low alloy steel, carbon steel, or stainless steel. The support member 3905, the mandrel launcher 3910, the tubular member 3925, and the shoe 3940 are preferably selected to fit through a preexisting section of wellbore casing 3950. In this manner, the apparatus 3900 may be positioned within the wellbore casing 3970. The support member 3905 is releasably coupled to the mandrel launcher 3910. In this manner, the support member 3905 may be decoupled from the mandrel launcher 3910 upon the completion of an extrusion operation.

The mandrel launcher 3910 is coupled to the support member 3905 and the tubular member 3925. The mandrel launcher 3910 preferably comprise a tubular member having a variable cross-section and a reduced wall thickness in order to facilitate the radial expansion process. The cross-sectional area of the mandrel launcher 3910 at one end is adapted to mate with the mandrel 3915, and at the other end, the cross-sectional area of the mandrel launcher 3910 is adapted to match the cross-sectional area of the tubular member 3925. The wall thickness of the mandrel launcher 3910 ranges from about 50 to 100 % of the wall thickness of the tubular member 3925 in order to facilitate the initiation of the radial expansion process.

The mandrel launcher 3910 may be fabricated from any number of conventional commercially available materials such as, for example, oilfield country tubular goods, low allow steel, stainless steel, or carbon steel. The mandrel launcher

3910 is fabricated from oilfield country tubular goods having higher strength but lower wall thickness than the tubular member 3925 in order to optimally match the burst strength of the tubular member 3925. The mandrel launcher 3910 is removably coupled to the tubular member 3925. In this manner, the mandrel launcher 3910 may be removed from the wellbore 3960 upon the completion of an extrusion operation.

The mandrel 3915 is coupled to the mandrel launcher 3910. The mandrel 3915 preferably comprise an annular member having a conic section fabricated from any number of conventional commercially available materials such as, for example, tool steel, carbon steel, ceramics, or composite materials. The angle of attack of the conic section of the mandrel 3915 ranges from about 10 to 30 degrees in order to optimally expand the mandrel launcher 3910 and the tubular member 3925 in the radial direction. The surface hardness of the conic section of the mandrel 3915 ranges from about 58 to 62 Rockwell C in order to optimally provide high strength and resist wear and galling. The mandrel 3915 is expandable in order to further optimally augment the radial expansion process.

The fluid passage 3920 is positioned within the mandrel 3915. The fluid passage 3920 is preferably adapted to convey fluidic materials such as cement, water, epoxy, lubricants, and slag mix at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The fluid passage 3920 preferably includes an inlet 3965 adapted to receive a plug, or other similar device. In this manner, the interior chamber 3970 above the mandrel 3915 may be fluidicly isolated from the interior chamber 3975 below the mandrel 3915.

The tubular member 3925 is coupled to the mandrel launcher 3910, the slips 3930 and the seals 3935. The tubular member 3925 preferably comprises a tubular member fabricated from any number of conventional commercially available materials such as, for example, low alloy steel, carbon steel, stainless steel, or oilfield country tubular goods. The tubular member 3925 is fabricated from oilfield country tubular goods.

The slips 3930 are coupled to the outside surface of the tubular member 3925. The slips 3930 preferably are adapted to couple to the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3925. In

this manner, the slips 3930 provide structural support for the expanded tubular member 3925. The slips 3930 may comprise any number of conventional commercially available slips, modified in accordance with the teachings of the present disclosure.

The seals 3935 are coupled to the outside surface of the tubular member 3925. The seals 3935 preferably provide a fluidic seal between the outside surface of the expanded tubular member 3925 and the interior walls of a casing, pipeline or other structure upon the radial expansion of the tubular member 3925. In this manner, the seals 3935 provide a fluidic seal for the expanded tubular member 3925. The seals 3935 may comprise any number of conventional commercially available seals such as, for example, lead, rubber or epoxy. The seals 3935 comprise Stratalok epoxy material available from Halliburton Energy Services in order to optimally provide structural support for the typical tensile and compressive loads.

The shoe 3940 is coupled to the tubular member 3925. The shoe 3940 preferably comprises a substantially tubular member having a fluid passage 3945 for conveying fluidic materials from the chamber 3975 to the annular region 3970 outside of the apparatus 3900. The shoe 3940 may comprise any number of conventional commercially available shoes modified in accordance with the teachings of the present disclosure.

During operation of the apparatus 3900, the apparatus 3900 is preferably lowered into a wellbore 3960 having a preexisting section of wellbore casing 3975. The apparatus 3900 is positioned with at least a portion of the tubular member 3925 overlapping with a portion of the wellbore casing 3975. In this manner, the radial expansion of the tubular member 3925 will preferably cause the outside surface of the expanded tubular member 3925 to couple with the inside surface of the wellbore casing 3975. The radial expansion of the tubular member 3925 will also cause the slips 3930 and seals 3935 to engage with the interior surface of the wellbore casing 3975. In this manner, the expanded tubular member 3925 is provided with enhanced structural support by the slips 3930 and an enhanced fluid seal by the seals 3935.

As illustrated in FIG. 24B, after placement of the apparatus 3900 in an overlapping relationship with the wellbore casing 3975, a fluidic material 3980 is preferably pumped into the chamber 3970. The fluidic material 3980 then passes through the fluid passage 3920 into the chamber 3975. The fluidic material 3980 then

passes out of the chamber 3975, through the fluid passage 3945, and into the annular region 3970. The fluidic material 3980 is pumped into the chamber 3970 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to optimally provide operational efficiency. The fluidic material 3980 comprises a hardenable fluidic sealing material in order to form a hardened outer annular member around the expanded tubular member 3925.

As illustrated in FIG. 24C, at some later point in the process, a ball 3985, plug or other similar device, is introduced into the pumped fluidic material 3980. The ball 3985 mates with and seals off the inlet 3965 of the fluid passage 3920. In this manner, the chamber 3970 is fluidicly isolated from the chamber 3975.

As illustrated in FIG. 24D, after placement of the ball 3985 in the inlet 3965 of the fluid passage 3920, a fluidic material 3990 is pumped into the chamber 3970. The fluidic material is preferably pumped into the chamber 3970 at operating pressures and flow rates ranging from about 0 to 9,000 psi and 0 to 3,000 gallons/minute in order to provide optimal operating efficiency. The fluidic material 3990 may comprise any number of conventional commercially available materials such as, for example, water, drilling mud, cement, epoxy, or slag mix. The fluidic material 3990 comprises a non-hardenable fluidic material in order to maximize operational efficiency.

Continued pumping of the fluidic material 3990 increases fluidic material 3980 increases the operating pressure within the chamber 3970. The increased operating pressure in the chamber 3970 then causes the mandrel 3915 to extrude the mandrel launcher 3910 and tubular member 3925 off of the conical face of the mandrel 3915. The extrusion of the mandrel launcher 3910 and tubular member 3925 off of the conical face of the mandrel 3915 causes the mandrel launcher 3910 and tubular member 3925 to expand in the radial direction. Continued pumping of the fluidic material 3990 preferably causes the entire length of the tubular member 3925 to expand in the radial direction.

The pumping rate and pressure of the fluidic material 3990 is reduced during the latter stages of the extrusion process in order to minimize shock to the apparatus 3900. The apparatus 3900 includes shock absorbers for absorbing the shock caused by the completion of the extrusion process. The extrusion process causes the mandrel 3915 to move in an axial direction 3995.

As illustrated in FIG. 24E, Upon the completion of the extrusion process, the support member 3905, packer 3910, first fluid conduit 3915, annular seal 3930, second fluid conduit 3935, mandrel 3945, and mandrel launcher 3950 are removed from the wellbore 3980. The resulting new section of wellbore casing includes the preexisting wellbore casing 3975, the expanded tubular member 3925, the slips 3930, the seals 3935, the shoe 3940, and an outer annular layer 4000 of hardened fluidic material.

The apparatus 3900 is used to repair a preexisting wellbore casing or pipeline. Both ends of the tubular member 3955 preferably include slips 3960 and seals 3965.

The apparatus 3900 is used to form a tubular structural support for a building or offshore structure.

Referring to FIGS. 25 and 26, the optimal relationship between the angle of attack of an expansion mandrel and the minimally required propagation pressure during the expansion of a tubular member will now be described. As illustrated in FIG. 25, during the radial expansion of a tubular member 4100 by an expansion mandrel 4105, the expansion mandrel 4105 is displaced in the axial direction. The angle of attack α of the conical surface 4110 of the expansion mandrel 4105 directly affects the required propagation pressure P_{PR} necessary to radially expand the tubular member 4100. Referring to FIG. 26, for typical grades of materials and typical geometries, the propagation pressure P_{PR} is minimized for an angle of attack of approximately 25 degrees. Furthermore, the optimal range of the angle of attack α ranges from about 10 to 30 degrees in order to minimize the range of required minimum propagation pressure P_{PR}.

Referring to FIG. 27, an expandable threaded connection 4300 will now be described. The expandable threaded connection 4300 preferably includes a first tubular member 4305, a second tubular member 4310, a threaded connection 4315, an O-ring groove 4320, and an O-ring 4325.

The first tubular member 4305 includes an inside wall 4330 and an outside wall 4335. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4310 includes an inside wall 4340 and an outside wall 4345. The second tubular member 4310 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4305 and 4310, may comprise any number of conventional commercially available members. The inside and outside diameters of the first and second tubular members, 4305 and 4310, are substantially equal. In this manner, the burst strength of the tubular members, 4305 and 4310, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4315 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4315 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4305 to the second tubular member 4310 is optimized.

The O-ring groove 4320 is preferably provided in the threaded portion of the interior wall 4340 of the second tubular member 4310. The O-ring groove 4320 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4320 is preferably selected to permit the O-ring 4325 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4345 of the second tubular member 4310 during and upon the completion of the radial expansion process is minimized.

The O-ring 4325 is supported by the O-ring groove 4320. The O-ring 4325 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4305 and the second tubular member 4310 throughout and upon the completion of the radial expansion process.

Referring to FIG. 28, an expandable threaded connection 4500 will now be described. The expandable threaded connection 4500 includes a first tubular member 4505, a second tubular member 4510, a threaded connection 4515, an O-ring groove 4520, and an O-ring 4525.

The first tubular member 4505 includes an inside wall 4530 and an outside wall 4535. The first tubular member 4305 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4510 includes an inside wall 4540 and an outside wall 4545. The second tubular member 4510 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4505 and 4510, may comprise any number of conventional commercially available members. The inside and outside diameters of the first and second tubular members, 4505 and 4510, are substantially equal. In this manner, the burst strength of the tubular members, 4505 and 4510, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4515 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4515 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4505 to the second tubular member 4510 is optimized.

The O-ring groove 4520 is preferably provided in the threaded portion of the interior wall 4540 of the second tubular member 4510 immediately adjacent to an end portion of the threaded connection 4515. In this manner, the sealing effect provided by the O-ring 4525 is optimized. The O-ring groove 4520 is preferably adapted to receive and support one or more O-rings. The volumetric size of the O-ring groove 4520 is preferably selected to permit the O-ring 4525 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4545 of the second tubular member 4510 during and upon the completion of the radial expansion process is minimized.

The O-ring 4525 is supported by the O-ring groove 4520. The O-ring 4525 optimally ensures that a fluid-tight seal is maintained between the first tubular member 4505 and the second tubular member 4510 throughout and upon the completion of the radial expansion process.

Referring to FIG. 29, an expandable threaded connection 4700 will now be described. The expandable threaded connection 4700 includes a first tubular member 4705, a second tubular member 4710, a threaded connection 4715, an O-ring groove 4720, a first O-ring 4725, and a second O-ring 4730.

The first tubular member 4705 includes an inside wall 4735 and an outside wall 4740. The first tubular member 4705 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4710 includes an inside wall 4745 and an outside wall 4750. The second tubular member 4710

preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4705 and 4710, may comprise any number of conventional commercially available members. The inside and outside diameters of the first and second tubular members, 4705 and 4710, are substantially equal. In this manner, the burst strength of the tubular members, 4705 and 4710, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4715 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4715 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4705 to the second tubular member 4710 is optimized.

The O-ring groove 4720 is preferably provided in the threaded portion of the interior wall 4745 of the second tubular member 4710 immediately adjacent to an end portion of the threaded connection 4715. In this manner, the sealing effect provided by the O-rings, 4725 and 4730, is optimized. The O-ring groove 4720 is preferably adapted to receive and support a plurality of O-rings. The volumetric size of the O-ring groove 4720 is preferably selected to permit the O-rings, 4725 and 4730, to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4750 of the second tubular member 4710 during and upon the completion of the radial expansion process is minimized.

The O-rings, 4725 and 4730, are supported by the O-ring groove 4720. The pair of O-rings, 4725 and 4730, optimally ensure that a fluid-tight seal is maintained between the first tubular member 4705 and the second tubular member 4710 throughout and upon the completion of the radial expansion process. In particular, the use of a pair of adjacent O-rings provides redundancy in the seal between the first tubular member 4705 and the second tubular member 4710.

Referring to FIG. 30, an expandable threaded connection 4900 will now be described. The expandable threaded connection 4900 includes a first tubular member 4905, a second tubular member 4910, a threaded connection 4915, a first O-ring

groove 4920, a second O-ring grove 4925, a first O-ring 4930, and a second O-ring 4935.

The first tubular member 4905 includes an inside wall 4940 and an outside wall 4945. The first tubular member 4905 preferably comprises an annular member having a substantially constant wall thickness. The second tubular member 4910 includes an inside wall 4950 and an outside wall 4955. The second tubular member 4910 preferably comprises an annular member having a substantially constant wall thickness.

The first and second tubular members, 4905 and 4910, may comprise any number of conventional commercially available tubular members. The inside and outside diameters of the first and second tubular members, 4905 and 4910, are substantially equal. In this manner, the burst strength of the tubular members, 4905 and 4910, are substantially equal. This minimizes the possibility of a catastrophic failure during the radial expansion process.

The threaded connection 4915 may comprise any number of conventional threaded connections suitable for use with tubular members. The threaded connection 4915 comprises a pin-and-box threaded connection. In this manner, the assembly of the first tubular member 4905 to the second tubular member 4910 is optimized.

The first O-ring groove 4920 is preferably provided in the threaded portion of the interior wall 4950 of the second tubular member 4910 that is separated from an end portion of the threaded connection 4915. In this manner, the sealing effect provided by the O-rings, 4930 and 4935, is optimized. The first O-ring groove 4920 is preferably adapted to receive and support one more O-rings. The volumetric size of the first O-ring groove 4920 is preferably selected to permit the O-ring 4930 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4955 of the second tubular member 4910 during and upon the completion of the radial expansion process is minimized.

The second O-ring groove 4925 is preferably provided in the threaded portion of the interior wall 4950 of the second tubular member 4910 that is immediately adjacent to an end portion of the threaded connection 4915. In this manner, the sealing effect provided by the O-rings, 4930 and 4935, is optimized. The second O-ring groove 4925 is preferably adapted to receive and support one more O-rings. The

volumetric size of the second O-ring groove 4925 is preferably selected to permit the O-ring 4935 to expand at least approximately 20% in the axial direction during the radial expansion process. In this manner, deformation of the outer surface 4955 of the second tubular member 4910 during and upon the completion of the radial expansion process is minimized.

The O-rings, 4930 and 4935, are supported by the O-ring grooves, 4920 and 4925. The use of a pair of O-rings, 4930 and 4935, that are axially separated optimally ensures that a fluid-tight seal is maintained between the first tubular member 4905 and the second tubular member 4910 throughout and upon the completion of the radial expansion process. In particular, the use of a pair of O-rings provides redundancy in the seal between the first tubular member 4905 and the second tubular member 4910.

The expandable threaded connections 4300, 4500, 4700, and/or 4900 are used in combination with one or more of the arrangements illustrated in FIGS. 1-24E in order to optimally expand a plurality of tubular members coupled end to end using the expandable threaded connections 4300, 4500, 4700 and/or 4900.

Although illustrative embodiments of the invention have been shown and described, a wide range of modification, changes and substitution is contemplated in the foregoing disclosure. In some instances, some features of the present invention may be employed without a corresponding use of the other features.

The following Registered Trade Marks are referred to in the specification

Super Seal II
Teflon
Lubriplate
EZ Drill
Halliburton
Cameron
Breda
Petroline

Conversion to metric units of imperial units used throughout the specification:

0.75 to 47 inches and 1.05 to 48 inches (0,02 to 1,19 metres and 0,03 to 1,22 metres)
3 to 15.5 inches and 3.5 to 16 inches (0,08 to 0,40 metres and 0,09 to 0,41 metres)
40 to 20,000 feet (12,19 to 6.096,00 metres)
0 to 3,000 gallons/minute and 0 to 9,000 psi (0 to 189,24 litres/sec. and 0 to 6.327.900,00 Kg/m^2)
1,000 to 1,000,000 lbf (4.448,00 Newtons to 4.448.000,00 Newtons)
0 to 5000 psi and 0 to 1,500 gallons/min (0 to 3.515.500,00 Kg/m^2 and 0 to 94,62 litres/sec.)
400 to 10,000 psi and 30 to 4,000 gallons/min (281.240,00 to 7.031.000,00 Kg/m^2 and 1,89 to 252,32 litres/sec.)
500 to 9,000 psi and 40 to 3,000 gallons/min (351.550,00 to 2.109.300,00 Kg/m^2 and 2,52 to 189,24 litres/sec.)
500 to 9,000 psi (351.550,00 to 2.109.300,00 Kg/m^2) --.
0 to 5 ft/sec (0 to 91,45 metre/minute)
0 to 2 ft/sec (0 to 36,58 metre/minute)
50 to 20,000 psi (35.155,00 to 14.062.000,00 Kg/m^2) --.
400 to 10,000 psi (281.240,00 to 7.031.000,00 Kg/m^2) --.
5 ft (1,52 metres)
1.05 to 48 inches and 1/8 to 2 inches (0,03 to 1,22 metres and 0,003 to 0,05 metres)

3.5 to 16 inches and 3/8 to 1.5 inches (0,09 to 0,41 metres and 0,01 to 0,04 metres)

2.5 to 50 inches and 1/16 to 1.5 inches (0,06 to 1,27 metres and 0,002 to 0,04 metres)

3.5 to 19 inches and 1/8 to 1.25 inches (0,09 to 0,48 metres and 0,003 to 0,032 metres)

2.5 to 50 inches and 1/16 to 1.25 inches (0,06 to 1,27 metres and 0,002 to 0,032 metres)

35 to 19 inches and 1/8 to 1.25 inches (0,09 to 0,48 metres and 0,003 to 0,032 metres)

40 to 20,000 ft (12,19 metres to 6.096,00 metres)

40 to 3,000 gallons/minute and 500 to 9,000 psi (2,52 to 189,24 litres/sec. and 351.550,00 to 6.327.900,00 Kg/m^2)

0 to 500 gallons/minute and 0 to 1,000 psi (0 to 31,54 litres/sec. and 0 to 703.100,00 Kg/m^2)

40,000 to 135,000 psi (28.124.000,00 to 94.918.500,00 Kg/m^2)

1/16 to 1.5 inches (0,002 to 0,0381 metres)

1/8 to 1.25 inches (0,003 to 0,032 metres)

1.05 to 48 inches (0,03 to 1,22 metres)

3.5 to 19 inches (0,09 to 0,48 metres)

2 to 5 feet (0,61 to 1,52 metres)

0 to 9,000 psi (0 to 6.327.900,00 Kg/m^2)

0.125 to 3 inches (0,003 to 0,0762 metres)

0.25 to 0.75 inches (0,00635 to 0,1905 metres)

1 to 47 inches (0,0254 to 1,1938 metres)

0 to 9,000 psi and 0 to 3,000 gallons/minute (0 to 6.327.900,00 Kg/m^2 and 0 to 189,24 litres/sec.)

0 to 5,000 psi and 0 to 1,500 gallons/minute (0 to 3.515.500,00 Kg/m^2 and 0 to 94,62 litres/sec.)

1,200 to 8,500 psi (843.720,00 to 5.976.350,00 Kg/m^2)

40 to 1,250 gallons/min (2,52 to 78,85 litres/sec.)

0 to 5,000 psi and 0 to 1,500 gallons/min (0 to 3.515.500,00 Kg/m^2 and 0 to 94,62 litres/sec.)

1200 to 8500 psi and 40 to 1,500 gallons/min (843.720,00 to 5.976.350,00 Kg/m^2 and 2,52 to 141.930,00 litres/sec.)

1200 to 8500 psi (843.720,00 to 5.976.350,00 Kg/m^2)

(

500 to 10,000 psi (351.550,00 to 7.031.000,00 Kg/m^2)

3/8 to 1 ½ inches and 3 ½ to 16 inches (0,009525 to 0,0381 metres and 0,0889 to 0,4064 metres)

0.625 to 0.75 inches and 3 to 19 inches (0,015875 to 0,01905 metres and 0,0762 to 0,4826 metres)

5,000 to 20,000 psi (3.515.500 to 14.062.000,00 Kg/m^2)

0.125 to 1.5 inches (0,003 to 0,038 metres)

0.25 to 1.0 inches (0,00635 to 0,0254 metres)

120 to 2400 inches (3,048 to 60,96 metres)

240 to 480 inches (6,096 to 12,192 metres)

0.05 to 0.75 inches (0,00127 to 0,01905 metres)

0.1 to 0.5 inches (0,00254 to 0,0127 metres)

0 to 750,000 lbf (0 to 103.725,00 Newtons)

0 to 500 gallons/minute and 0 to 9,000 psi (0 to 31,54 litres/sec. and 0 to 6.327.900,00 Kg/m^2.)

0 to 5,000 psi (0 to 3.515.500,00 Kg/m^2)

0 to 9,000 psi and 0 to 500 gallons/minute (0 to 6.327.900,00 Kg/m^2 and 0 to 31,54 litres/sec.)

500 to 5,000 psi and 0 to 500 gallons/minute (351.550,00 to 3.515.500 Kg/m^2 and 0 to 31,54 litres/sec.)

0.0025 to 0.05 inches (0,0000635 to 0,00127 metres)

0.005 to 0.01 inches (0,00127 to 0,000254 metres)

0.025 to 0.375 inches (0,000635 to 0,009525 metres)

0.025 to 0.125 inches (0,000635 to 0,0003175 metres)

2 to 34 inches (0,0508 to 0,8636 metres)

3 to 28 inches (0,0762 to 0,7112 metres)

0.15 to 1.5 inches (0,00381 to 0,0381 metres)

0 to 4,500 psi and 0 to 3,000 gallons/minute (0 to 3.163.950,00 Kg/m^2 and 0 to 189,24 litres/sec)

0 to 4,500 psi and 0 to 4,500 gallons/minute (0 to 3.163.950,00 Kg/m^2 and 0 to 283,86 litres/sec)

0 to 3,500 psi and 0 to 1,200 gallons/minute (0 to 2.460.850,00 Kg/m^2 and 0 to 75,696 litres/sec)

100 to 1,000 psi (70.310,00 to 703.100,00 Kg/m^2)

0 to 500 psi (0 to 351.550,00 Kg/m^2)

10 to 45 ft (3,048 metres to 13,716 metres)

0.005 to 0.125 inches (0,000127 to 0,0003175 metres)

500 to 40,000 psi (351.550,00 to 28.124.000,00 Kg/m^2)

0 to 9,000 psi and 0 to 5,000 gallons/minute (0 to 6.327.900,00 Kg/m^2 and 0 to 79.264,426 litres/sec.)

10 to 45 ft (3,048 metres to 13,716 metres)

0 to 10,000 psi and 0 to 3,000 gallons/minute (0 to 7.031.000,00 Kg/m^2 and 0 to 189,24 litres/sec.)

0 to 12,000 psi and 0 to 3,500 gallons/minute (0 to 8.437.200,00 Kg/m^2 and 0 to 220,78 litres/sec)

0 to 12,000 psi and 0 to 10,000 gallons/minute (0 to 8.437.200,00 Kg/m^2 and 0 to 630,80 litres/sec)

0 to 5,000 psi and 40 to 3,000 gallons/minute (0 to 3.515.500,00 Kg/m^2 and 2,5232 to 189,24 litres/sec)

1,000 to 9,000 psi (703.100,00 to 6.327.900,00 Kg/m^2)

3 to 15.5 inches (0,0762 to 0,3937 metres)

3.5 to 16 inches (0,0889 to 0,4064 metres)

0 to 9,000 psi (0 to 6.327.900,00 Kg/m^2)

0 to 3,000 gallons/minute (0 to 189,24 litres/sec.)

CLAIMS:

1. A method for sealing a connection between adjoining tubular bodies comprising:

threadably engaging a threaded axial end of a first tubular body within a threaded axial end opening of a second tubular body whereby an annular chamber is defined between the first and the second tubular bodies;

disposing a sealing component in the annular chamber between the first and second tubular bodies; and

radially expanding the first and the second tubular bodies to compress the sealing component between the first and second tubular bodies to seal the annular chamber between the first and second tubular bodies.

2. The method of claim 1, wherein the sealing component expands at least about 20 percent in the axial direction within the annular chamber during the radial expansion.

3. A method for forming a seal between telescopically and threadably engaged, tubular bodies comprising:

disposing a seal component in an overlapping annular area between first and second telescopically and threadedly engaged tubular bodies; and

radially expanding the first and the second tubular bodies to compress the seal component for forming a seal between said first and second tubular bodies in the overlapping annular area.

4. The method of claim 2, wherein the seal component expands at least about 20 percent in the axial direction within the annular area during the radial expansion.

5. The method of claim 3, wherein the seal component is carried in an annular groove formed in one of said first and said second tubular bodies in the overlapping annular area.

6. A method for sealing telescopically engaged tubular bodies comprising:

threadably engaging a threaded axial end of a first tubular body into a threaded axial end of a second, larger diameter tubular body whereby the second body overlaps the first body in an axially extending threaded annular area adjacent the axial ends of the first and the second tubular bodies;

disposing a deformable sealing component in the axially extending threaded annular area between the first and second tubular bodies; and

radially expanding the first and the second tubular bodies; and compressing the deformable sealing component during the expanding for forming a seal between the first and the second tubular bodies in the axially extending threaded annular area.

7. The method of claim 6, wherein the sealing component expands at least about 20 percent in the axial direction within the annular area during the radial expansion.

8. A method for sealing a connection between adjoining tubular pipe bodies in a string of well pipe for use in a wellbore, comprising:

disposing a sealing component on one or both of a first axial end of a first tubular pipe body and a second axial end of a second tubular pipe body;

engaging the first axial end of the first tubular pipe body within the second axial end of the second tubular pipe body whereby an annular area containing the sealing component is defined between the first and the second axial ends; and

disposing the string of well pipe in a surrounding well bore; and radially expanding the first and the second axial ends toward the surrounding well bore to compress the sealing component between the first tubular pipe body and the second tubular pipe body to seal the annular area between the first tubular pipe body and the second tubular pipe body.

9. The method of claim 8, wherein the string of well pipe is comprised of multiple adjoining tubular pipe bodies and further comprising radially expanding the multiple adjoining tubular pipe bodies in the string of well pipe.

10. The method of claim 8 wherein the seal component is carried in an annular groove formed in one of the first and second axial ends within the annular area.

11. The method of claim 8, wherein the seal component expands at least about 20 percent in the axial direction within the annular area during the radial expansion.

12. The method of claim 10, wherein the second axial end comprises a threaded box connection and the annular groove is formed in an internal surface of the box connection.

13. The method of claim 10, wherein the first axial end comprises an externally threaded pin connection and the second axial end comprises an internally threaded box connection and wherein the pin connection and the box connection are threadedly engaged together.

14. The method of claim 13, wherein the seal component is carried in an annular groove formed in an internal surface of the internally threaded box connection and wherein the sealing component comprises an elastomeric seal ring and a separate spacer ring.

15. The method of claim 1, wherein the first tubular body comprises a first inner diameter, and the second tubular body comprises a second inner diameter, wherein the first inner diameter is substantially equal to the second inner diameter.

16. The method of claim 1, wherein the first tubular body comprises at least one thin wall section and a thick wall section.

17. The method of claim 1, wherein the second tubular body comprises at least one thin wall section and a thick wall section.

18. The method of claim 1, wherein the radially expanding comprises placing a mandrel within the first tubular body, pressurizing an annular region within the first

tubular body, and displacing the mandrel with respect to the first tubular body.

19. The method of claim 18, wherein the mandrel comprises a conical surface having an angle of attack ranging from about 10 to 30 degrees.

20. The method of claim 1, wherein the radially expanding comprises placing a mandrel within the second tubular body, pressurizing an annular region within the second tubular body, and displacing the mandrel with respect to the second tubular body.

21. The method of claim 20, wherein the mandrel comprises a conical surface having an angle of attack ranging from about 10 to 30 degrees.

22. The method of claim 1, further comprising placing the first and second tubular bodies in a borehole, wherein the borehole comprises a substantially constant internal diameter.

23. The method of claim 1, wherein the threaded axial ends of the first and second tubular bodies comprise a pin and box connection, wherein the pin and box connection is expandable.

24. The method of claim 23, wherein the sealing component is positioned within the pin and box connection within the annular chamber.

25. The method of claim 23, wherein the pin and box connection further comprises one or more male threads for engaging one or more female threads.

26. The method of claim 23, wherein the pin and box connection comprises one or more male threads for engaging one or more female threads; and wherein the annular chamber is disposed between the male threads.

27. The method of claim 23, wherein the pin and box connection further comprises

one or more male threads for engaging one or more female threads; and wherein the annular chamber is disposed between the female threads.

28. The method of claim 1, wherein the sealing component comprises two o-rings, the o-rings disposed within a groove formed in the first tubular body or the second tubular body.

29. The method of claim 1, wherein the sealing component comprises a first and a second o-ring, the first o-ring disposed within a first groove formed in the first tubular body or the second tubular body, and the second o-ring disposed within a second groove formed in the first tubular body or the second tubular body, wherein the first groove is axially separated from the second groove.

30. The method of claim 1, wherein the first tubular body comprises a threaded pipe pin, and the second tubular body comprises a threaded pipe box.

31. The method of claim 30, wherein the annular chamber comprises an annular groove, wherein the sealing component is carried in the annular groove, the annular groove defined in said threaded pipe pin or said threaded pipe box.

32. The method of claim 1, wherein the sealing component comprises a deformable material.

33. The method of claim 1, wherein the sealing component comprises a material selected from the group consisting of rubber, plastic, metal and epoxy.

34. The method of claim 1, wherein the first tubular body comprises a threaded pipe pin, and the second tubular body comprises a threaded pipe box, wherein the sealing component is disposed within an annular groove formed in an internal surface of the internally threaded pipe box.

35. The method of claim 1, wherein the radially expanding comprises installing the

first tubular body in a borehole, injecting a fluidic material in the borehole, and radially expanding and plastically deforming the first tubular body in the borehole by extruding the first tubular body off of a mandrel.

36. The method of claim 1, wherein the radially expanding comprises installing the second tubular body in a borehole, injecting a fluidic material in the borehole, and radially expanding the second tubular body in the borehole by extruding the second tubular body off of a mandrel.

37. The method of claim 1, wherein radially expanding further comprises placing an expansion apparatus within the first and second tubular bodies, the expansion apparatus comprising a support member, a mandrel, and a shoe.

38. The method of claim 37, wherein the mandrel comprises an expandable mandrel.

39. The method of claim 37, wherein the mandrel is drillable.

40. The method of claim 37, wherein the shoe comprises an interior portion, wherein the interior portion of the shoe is drillable.

41. The method of claim 37, further comprising lubricating at least one of an outer surface of the mandrel and an inner surface of the first and second tubular bodies.

42. The method of claim 1, further comprising placing an annular body of a curable fluidic sealing material between the first tubular body and a borehole.

43. The method of claim 1, further comprising placing an annular body of a curable fluidic sealing material between the second tubular body and a borehole.

44. The method of claim 18, further comprising lubricating at least one of an outer surface of the mandrel and an inner surface of the first tubular body.

45. The method of claim 20, further comprising lubricating at least one of an outer surface of the mandrel and an inner surface of the second tubular body.